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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

April 26, 2006

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on April 26, 2006, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

5 MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

6 BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE

7 + + + + +

8 WEDNESDAY,

9 APRIL 26, 2006

10 + + + + +

11 The subcommittee meeting convened at the

12 Nuclear Regulatory Commission, Two White Flint

13 North, Room T-2B3, 11545 Rockville Pike, at 8:30

14 a.m., Richard B. Denning, Chair, presiding,

15

16 SUBCOMMITTEE MEMBERS PRESENT:

17 RICHARD B. DENNING, Chair

18 SANJOY BANERJEE ACRS, Consultant

19 THOMAS S. KRESS

20 OTTO L. MAYNARD

21 JOHN D. SIEBER

22 GRAHAM B. WALLIS

23

24 ACRS STAFF PRESENT:

25 RALPH CARUSO

1 FIRSTENERGY STAFF:

2 BOB BAIN Stone & Webster

3 DON DURKOSH FENOC

4 BILL ETZEL FENOC

5 KEN FREDERICK FENOC

6 DAVID GRABSKI FENOC

7 JEFF HALL Westinghouse

8 NORM HANLEY Stone & Webster

9 GREG KAMMERDINER FENOC

10 COLIN KELLER FENOC

11 JAMES LASH FENOC

12 MARK MANOLERAS FENOC

13 PETE SENA FENOC

14 GEORGE STORLIS FENOC

15 MIKE TESTA FENOC

16

17 NRR STAFF PRESENT:

18 TIMOTHY COLBURN

19 STEVEN LAUR

20 GREGORY MAKAR

21 ROBERT PETTIS

22 MARK RUBIN

23 THOMAS SCARBROUGH

24 ANGELO STUBBS

25

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1 P-R-O-C-E-E-D-I-N-G-S

2 8:33 a.m.

3 CHAIRMAN DENNING: We are now back in

4 session. And this is Wednesday, April the 26th.

5 And we're going to start off discussing mechanical

6 impacts and Mike Testa.

7 MR. TESTA: First I'd like to thank the

8 Committee for the opportunity to speak here today.

9 My name is Mike Testa, I'm the extended power uprate

10 Project Manager for Beaver Valley.

11 A little background on myself. I have

12 23 years of experience at Beaver Valley Power

13 Station. The last five year I've been the uprate

14 Project Manager and I also was on the full potential

15 project from the beginning.

16 Today I'll be discussing the mechanical

17 impacts that the uprate has on Beaver Valley Power

18 Station.

19 Next slide, John.

20 I'll be discussing the steam generators,

21 balance of plant heat exchangers, vibration

22 monitoring program for the secondary piping systems,

23 cooling water systems and flow accelerated

24 corrosion, of which we'll have our program owner

25 come up and speak on that program.

1 Today if there's any questions, I have
2 Jeff Hall from Westinghouse to assist me as well as
3 Bob Bain from Stone & Webster.
4 For steam generator vibration, we looked
5 at the first thing, we used a thermal-hydraulic code
6 Athos that computes the thermal-hydraulic parameters
7 the tubes so the tube bundle would be subjected to.
8 We looked at the vibration potential in
9 the U-bend and tube bundle entrance region. Out of
10 two vibration mechanisms that were considered, were
11 fluid-elastic instability, vortex shedding and
12 random turbulent excitation.
13 And we also looked at tube wear. And
14 that's tube wear in the U-bed radio at the
15 antivibration bar interface.
16 The tube bundles, just the difference
17 between the units now. For Unit 1 we replaced the
18 steam generators. We discussed that yesterday. Model
19 54. Just installed in fact a few weeks ago here.
20 The model 54 was designed for uprate conditions so
21 the stress report, the design report considered
22 uprate.
23 For Unit 2 we have the Series 51 steam
24 generator, of course, which now will see increased
25 flow because the uprate.

1 We reviewed the --

2 MEMBER WALLIS: I presume the steam

3 generators is plural and you installed three of

4 them?

5 MR. TESTA: Yes.

6 MEMBER WALLIS: Not just one?

7 MR. TESTA: Yes, correct. That's

8 correct. Yes. Three loop PWR 3 steam generators.

9 We looked at the flow induced vibration

10 effects --

11 DR. BANERJEE: What's the difference

12 between the two?

13 MR. TESTA: Between a model 54 and 51?

14 Jeff?

15 MR. HALL: Yes. This is Jeff Hall from

16 Westinghouse.

17 The differences are really many. With

18 respect to the tube material itself the 51M is a 600

19 mm tubing where the 54F is a 690 thermally treated

20 tubing. So issues such as stress cracking are

21 greatly reduced with the new model generator.

22 The support plates are stainless for the

23 new model generator versus carbon steel support

24 plates.

25 The antivibration bars are better

1 designed for the new unit.

2 DR. BANERJEE: What does that better

3 design mean?

4 MR. HALL: The support conditions are

5 more assured. Where for the 51M sometimes you could

6 pick up gaps between AVBs and the tubes, with the

7 newer design with the reduced gaps you have a

8 reduced potential for wear at the AVB sites.

9 DR. BANERJEE: So are these just gaps or

10 are there actually things holding the tubes in

11 place?

12 MR. HALL: Well, you could think of it

13 as a bar that's inserted between the tubes in the U-

14 bend region. It's a flat bar. Essentially it

15 provides a support location to prevent the tube from

16 moving in the out of plane direction.

17 DR. BANERJEE: But they're not broach

18 plates or anything like that?

19 MR. HALL: Well with respect to the

20 support plates. The support plates are in fact

21 broached.

22 DR. BANERJEE: Okay.

23 MR. HALL: Where the 51M is a circular

24 drilled hole.

25 DR. BANERJEE: And the 54F?

1 MR. HALL: The 54F is a broached
2 configuration.
3 MR. KAMMERDINER: Excuse me, Jeff. This
4 is Greg Kammerdiner.
5 Back on the AVBs, the other difference
6 with the 54Fs, there's an extra set of AVBs. 51s
7 have two sets of AVBs, the 54s have three. So
8 there's more support in the upper bundle because
9 there is an extra set of AVBs in the 54.
10 DR. BANERJEE: And the number of tubes
11 are the same?
12 MR. KAMMERDINER: There's approximately
13 400 tubes more in the 54?
14 MR. HALL: Yes.
15 DR. BANERJEE: Four hundred out of how
16 many?
17 MR. KAMMERDINER: The 51Ms have 3,376.
18 The 54s approximately 400 more.
19 DR. BANERJEE: Ten percent more?
20 MR. KAMMERDINER: Yes.
21 DR. BANERJEE: Thanks.
22 MR. KAMMERDINER: Fifty-four stands for
23 54,000 square feet of heat transfer area. The 51, is
24 51,000 square feet.
25 DR. BANERJEE: Thank you.

1 MEMBER WALLIS: So the AVBs limit the
2 amplitude of the oscillation, but they also give the
3 tubes something to rub against, to bang against?
4 MR. HALL: Yes.
5 MEMBER WALLIS: Well, they're good and
6 bad at the same time in a way.
7 MR. HALL: Beg your pardon?
8 MEMBER WALLIS: They're both and bad?
9 MR. HALL: Well, yes. No, they're
10 actually all good.
11 MEMBER WALLIS: Okay. But it says here
12 tube wear at IBBs. There is some rubbing or
13 something going on?
14 MR. HALL: Yes. And that's primarily a
15 result of the fit up between the tube and the bar
16 itself. If you have the ability to move back and
17 forth, well the tube is going to move back and
18 forth. But if you're holding it sufficiently so
19 that you don't have relative motion, well then you
20 don't get wear.
21 MEMBER SIEBER: The AVBs go in the U-
22 bend area, not below?
23 MR. HALL: That's correct.
24 MEMBER SIEBER: The old ones sometimes
25 they weren't long enough to catch all the tubes. So

1 you would end up with a tube that's not supported.

2 MR. HALL: Yes. And actually in both

3 cases, the 51 in particular, there are some tubes in

4 the U-bend region that are unsupported.

5 MR. TESTA: And actually, that's a lead

6 in for the next bullet where we looked at -- go

7 back, John.

8 Yes for Unit 2 again for the series 51,

9 unsupported U-bends were reviewed for increased

10 fatigue. And because the analysis that was

11 performed, there was six tubes that we had to take

12 out of service. And we did that.

13 Okay. As far as the next slide here, I

14 just wanted to touch on the steam dryer. Again,

15 look at the comparison between the PWR and the BWR.

16 Just a little description on the secondary steam

17 dryers on the steam generators. Now the main

18 difference is between the 51 and the 54 is that the

19 51s have a two tier arrangement for the secondary

20 dryers. I have sketch behind this to show that,

21 whereas the model 54 has a single tear arrangement.

22 It's better illustrated here. Again,

23 with the 51 they have two tiers of secondary steam

24 dryers. You can see the lines that are drawn. The

25 steam comes up and enters into the side region of

1 the secondary dryer and then flows up, comes up
2 through and then has a natural progression up
3 through the secondary dryers.
4 The flow velocity in that region is on
5 the order of 3½ to 4 feet per second. And you can
6 see the vicinity of the nozzle region there's no
7 structural components within the vicinity of the
8 nozzle.
9 CHAIRMAN DENNING: I realize that later
10 you're going to talk a little bit about experience.
11 But could you tell us at this point how much
12 experience is there with the 51 at the conditions
13 that you're now going to go to?
14 MR. HALL: With respect to these
15 conditions there's an immense amount of experience.
16 These steam dryers, this configuration is used in a
17 multitude of steam generator models, not just the
18 51s. The D models, D2, D3, D4, D5 all have a very
19 similar arrangement. 54F a very similar
20 arrangements. The Fs all have a two tier
21 arrangement.
22 The velocities coming out of that area
23 are all pretty much of the same order of magnitude.
24 I mean, a couple of feet per second one way or the
25 other, but they're all essentially the same.

1 Totally different orders of magnitude than some of
2 the boiling water reactor dryers.
3 MEMBER SIEBER: Well, the one thing you
4 don't have is a 180 degree change of direction.
5 MR. HALL: And all the consequences of
6 that with respect to the turbulence that you can
7 get, yes. It's all pretty much it comes out of the
8 steam dryers and it continues on right up to the
9 steam nozzle.
10 MEMBER SIEBER: The velocities are
11 pretty low. They're like --
12 DR. BANERJEE: Can you stay there. Can
13 you go back to that slide?
14 MR. TESTA: That one?
15 DR. BANERJEE: No, no, no.
16 MEMBER WALLIS: The velocities?
17 DR. BANERJEE: Yes.
18 MEMBER WALLIS: The one with the
19 velocities, 107.
20 DR. BANERJEE: The velocities.
21 MEMBER WALLIS: That's it.
22 DR. BANERJEE: That's it.
23 MEMBER WALLIS: There's no history of
24 problems with these dryers, I understand?
25 MR. TESTA: That's correct. In fact here

1 from this slide here it was to compare, again the 51
2 to the BWR. You can see that they have low
3 velocities up through the dryers at 3½ to 4 feet per
4 second where the BWR was on the order of 100 feet
5 per second. And there have been no operational
6 issues reported in the 51s or the 54s.
7 We had a backup slide just to show the
8 operating experience.
9 DR. BANERJEE: Can you, please?
10 MR. TESTA: Sure. Okay. So for
11 example, you know, well Beaver Valley which is going
12 to operate at 2910. The difference with the model
13 54 one tier secondary dryer in the Unit 2, with two
14 tier you can see the comparison to the other plants
15 that utilize the similar secondary steam dryer
16 arrangement.
17 MR. HALL: Yes, but these are not the
18 only plants to have this particular dryer
19 arrangement, too. There's many more.
20 MEMBER SIEBER: As far as megawatt
21 production, Beaver Valley and North Anna are about
22 the same so the operating experience from North Anna
23 at that power level, it's got a fair amount of time
24 behind it.
25 MR. TESTA: That's correct.

1 MEMBER SIEBER: So they aren't really
2 breaking any new ground here.
3 MR. TESTA: In fact, North Anna is on
4 the list here where they're operating at 2905.
5 MEMBER SIEBER: Got them beat by five?
6 MR. TESTA: Yes. Okay. Okay, John.
7 No, go forward.
8 Now if there's no other questions on the
9 steam generator, we also looked at balance of plant
10 heat exchangers. From the uprate looking at the
11 heat balance and the flow parameters that the
12 equipment would be subjected to. We looked at the
13 feedwater heaters and the feedwater heaters will
14 operate within the design capacity.
15 The moisture separator reheaters, we
16 went back to the vendor. We had a specific analysis
17 performed to show acceptability under the increased
18 flows.
19 As we mentioned yesterday, one of the
20 modifications that we're going to do is on the
21 condenser. Now our Unit 1 condenser was retubed a
22 while back. And at that time the condenser was
23 staked. Prior to the power escalation we will be
24 taking the condenser in order to limit the tube
25 vibration.

1 Vibration monitoring. This is a
2 monitoring program for the secondary side for the
3 balance of plant piping. We're going to monitor the
4 secondary systems pre and post-EPU. This is going
5 to include baseline walkdowns on each of the plants
6 which we've already done. We have documented
7 walkdowns.
8 Areas of interest where there's level of
9 vibration that causes us to pay particular attention
10 as we escalate power, we've identified those
11 locations.
12 All this is within the guidance of ASME
13 OM Part 3 that prescribes the walkdowns or the
14 acceptance criteria that could be used and the
15 method of performing this program.
16 CHAIRMAN DENNING: Could you help me a
17 little bit on a walkdown where you're looking for
18 vibration, what does one do quantitatively there?
19 MR. TESTA: Okay. What we do there is,
20 for example, we came up with a screening criteria.
21 We're looking at the displacement I'd say on the
22 order of an eighth of an inch. And we'll walk it
23 down to see if there's any signs, any noticeable
24 signs of vibration. And we basically have
25 documented from the plant, basically going from say

1 component to component, basically identifying if we
2 have vibration levels that would exceed that limit.
3 CHAIRMAN DENNING: Visually?
4 MR. TESTA: Visually. That's correct.
5 I have Bob Bain from Stone & Webster.
6 If you'd like to add?
7 MR. BAIN: Yes. This is Bob Bain from
8 Stone & Webster.
9 We followed the basic guidance of OM3 as
10 Mike says. The first test criterion we used was
11 visual on displacement of an eighth of an inch,
12 which is within the guidance provided in OM3. They
13 allow for visual measurements using simple devices
14 such as rulers, hand held type mechanical simple
15 devices like pencils, literally. And an eighth of
16 an inch peak to peak displacement is easily visual
17 on a focused walkdown. And as Mike says, these
18 walkdowns were basically focused.
19 Over the last three or four years,
20 actually, we took a schematics and basically
21 connected the dots from equipment. So from pump to
22 valve, valve to vent or drain, vent or drain to
23 branch lines. So it was a focused walkdown looking
24 at the piping, the components as well as the support
25 hardware.

1 And any observation, again eighth of an
2 inch was a fairly stringent criteria. Easily
3 visually noted. That would get it onto this list of
4 interest, as Mike identified.
5 And we followed up that list of interest
6 literally over the last three or four years for both
7 units.
8 CHAIRMAN DENNING: Is there quantitative
9 stuff that one can do? I mean, are there instruments
10 that you can go and put it up against the machine?
11 I mean, the equipment --
12 MR. TESTA: Yes, there are.
13 CHAIRMAN DENNING: -- and have a measure
14 of not only the displacement but the frequency?
15 MR. TESTA: Yes. There's a portable
16 device, hand held accelerometers. And, again, we
17 conduct these walkdowns. We use the experienced
18 engineers. And if there's any question about the
19 acceptance of the level of vibration, then we will
20 use accelerometers to record the displacement and
21 the frequency.
22 MR. BAIN: Yes. This is Bob Bain again.
23 And this hand held equipment that Mike
24 references actually gives you data in displacement
25 or velocity or acceleration. And OM3 allows you to

1 do more detailed evaluations if required using
2 velocity or displacement data. So the hand held is
3 a good device to give you the next level of detail
4 quantitatively.
5 MR. TESTA: Okay. Just the last mention
6 here, large equipment like the reactor coolant pump
7 and the turbine have continuous monitoring
8 available. So we'll be monitoring that as we
9 escalate power.
10 Okay, John.
11 Now the next area we looked at is
12 cooling systems. The bottom line here is that the
13 systems remain capable of dissipating heat for
14 normal shutdown and accident conditions.
15 WE looked at these following systems,
16 the flows were adequate without modification:
17 The river water system. Beaver Valley 1
18 the equivalent system service water for Unit 2;
19 The component cooling water;
20 Residual heat removal, and;
21 The safety injection containment
22 depressurization system which uses the recirc spray
23 heat exchangers.
24 Next slide.
25 Spent fuel cooling. We looked at spent

1 fuel cooling. As part of the project or the overall
2 initiative, which we started we said five to six
3 years ago, we looked at spent fuel cooling. And
4 there was an amendment that we put in where we
5 looked at the offload time. At that time we
6 performed the analysis to incorporate the uprate
7 decay heat loads.
8 MEMBER KRESS: Do you have dry casks on
9 the site?
10 MR. TESTA: Not at this point, no.
11 Still use the fuel pool.
12 MEMBER WALLIS: I think I remember your
13 burnup is the same as it was before essentially, is
14 that right?
15 MR. TESTA: Yes, I believe so. Yes.
16 The last area to touch on here is the
17 auxiliary feedwater system. The auxiliary feedwater
18 is fed from the condensate storage tank. The
19 condensate storage tank is sized for 9 hours of hot
20 standby conditions. And with the uprate or the
21 increased decay heat, we've revised the tech specs
22 to require 130,000 gallons useable volume for each
23 of the tanks for both Unit 1 and Unit 2.
24 The other thing with the aux feedwater
25 system, there were two accidents: The feedline

1 break and loss of normal feed that required us
2 crediting two aux feed pumps.
3 CHAIRMAN DENNING: I didn't understand
4 with regards to the tech spec limit and the 130,000
5 gallons. What do you do physically to assure that?
6 MR. TESTA: Basically we have the
7 calculated tank volume and maintain a level on the
8 tank.
9 CHAIRMAN DENNING: So it's a level on
10 the tank that has to be assured now that it's
11 slightly higher than it was previously?
12 MR. TESTA: Yes. Yes.
13 CHAIRMAN DENNING: Gotcha.
14 MR. DURKOSH: This is Don Durkosh from
15 Beaver Valley Operations.
16 Basically we obtained curves that show
17 based on indications available to us what the volume
18 is. And on every shift we have minimum levels that
19 we're required to verify on a shiftly basis. So
20 that's how we maintain our minimum tech spec values.
21 MEMBER MAYNARD: You didn't make any
22 modifications to the tank. You're just changing the
23 level setpoint there.
24 MR. TESTA: That's correct. That's
25 correct.

1 MR. CARUSO: Why would you not normally
2 keep the tank full?
3 MEMBER SIEBER: It goes up and down. You
4 have to have surge volume.
5 MR. TESTA: To answer that question we
6 normally do. As part of the review of our L5 logs
7 we typically, our levels are high. What we try to do
8 is basically clear the alarms. We have a low alarm
9 that indicates we're approaching a tech spec limit.
10 And normally we have a high alarm very close to the
11 overflow. So we try to maintain it within that
12 range so we have no alarms in the control room.
13 MR. TESTA: Okay. Again, just to finish
14 this out here, there are two accidents that required
15 us to credit two pumps. This was already in place
16 for Unit 2. And with the revised analysis Unit 1
17 will now require two pumps also for these two
18 accidents. It's basically accounting for the
19 increased decay heat plus the addition of the
20 cavitating venturies, which puts a little more
21 system resistance into the system.
22 CHAIRMAN DENNING: And that's two out of
23 how many?
24 MR. TESTA: Two out of three.
25 CHAIRMAN DENNING: And it had been one

1 out of three?

2 MR. TESTA: It had been one out of

3 three, just for Unit 1. Unit 2 was already

4 crediting two pumps.

5 Okay. Well, this completes my part of

6 the discussion. I have Dave Grabski here, which

7 he's our flow accelerated corrosion program owner,

8 and he'll talk about the program.

9 Thank you.

10 MR. GRABSKI: As Mike said, I'm Dave

11 Grabski. I am the FAC program owner.

12 A little background. I'm a FirstEnergy

13 employee. I worked at Beaver Valley and before that

14 Shippingport Atomic Power Station for a combined 26

15 years.

16 I've been the FAC program owner since

17 the early '90s.

18 Next slide.

19 The first bullet, the EPU effects

20 evaluated using CHECWORKS. So we've taken the

21 revised heat balance diagram parameters and using

22 the CHECWORKS models determined analytically what

23 we'd expect as far as our wear rates. With most

24 uprates, we've seen an increase in velocity and

25 temperature. And those two factors play differently

1 with different systems. Some systems we've seen a
2 decrease in our wear rates, and others we've seen a
3 slight increase.
4 The feedwater and extraction steam
5 systems, those systems had a decrease. Systems like
6 the feedwater heater drains, condensate have
7 increased. Again, because of the play of those
8 different parameters: Velocity and temperature
9 mainly.
10 In preparation for the uprate we've
11 actually replaced two extraction steam Ts because
12 of the increase in our SMR relief valve set point
13 that has cut into our margin between our measured
14 wall thickness and our required wall thickness.
15 Extraction steam is one system at Beaver Valley that
16 does wear due to the flow accelerated corrosion
17 mechanism.
18 CHAIRMAN DENNING: So there wasn't a
19 materials change, it was just a thickness change?
20 MR. GRABSKI: We have upgraded the
21 material to a chrome-molly. Basically anytime we
22 make piping replacements at Beaver Valley, we'll
23 upgrade to a chrome-molly. Chrome-molly is much
24 more resistent to this particular degradation
25 mechanism.

1 Based on the engineering evaluation
2 we're going to focus on a few more systems. Well,
3 not more systems, but more components within those
4 systems, on those systems that we expect an increase
5 in velocity. Mainly our moisture -- or I should say
6 the heat drain system from our 4th to 5th point
7 heaters, we had a significant velocity there. So
8 we're going to focus examinations in the next outage
9 there to get a baseline where we're at. And in the
10 future go back to these areas to see how they're
11 doing.
12 And there's some components at Beaver
13 Valley 1 and 2 in the 4th point heat drain line.
14 It's showing you in the next to the last column
15 there some of the wear rates we saw before the
16 outage. Very low. And heater drains is a low wear
17 system at Beaver Valley. But we do see some
18 increases based on the uprate.
19 DR. BANERJEE: Do you have a diagram
20 showing where these components are in the steam
21 cycle?
22 MR. GRABSKI: I don't have --
23 DR. BANERJEE: I have no idea where the
24 four point heat is or what -- I imagine that it's
25 extraction --

1 MEMBER WALLIS: This is a preheater.

2 DR. BANERJEE: Preheater?

3 MR. GRABSKI: Yes. We have six --

4 MEMBER WALLIS: Well, these aren't

5 safety concerns anyway. These are just

6 embarrassments for you if you break a pipe, it might

7 be dangerous for anyone who is around the pipe.

8 MR. GRABSKI: It could be a personnel

9 issue.

10 MEMBER WALLIS: It's dangerous for your

11 people, but it's not a nuclear --

12 MR. GRABSKI: That's correct. This is a

13 non-safety related piping systems.

14 MR. STORLIS: My name is George Storlis.

15 I'm a FENOC employee.

16 An in Operations I can get a little bit

17 of perspective to what the feed heater string is.

18 The feed heater string is compromised of six feed

19 heaters in line with the condensate feed system to

20 preheat the feed. The fourth point is fourth in

21 line, the sixth point being the lowest energy or

22 lowest pressure system and the first point being an

23 extraction steam of highest pressure off of the

24 turbine cycle. And the fourth point is in route to

25 that.

1 And we're talking pressures,
2 temperatures that compliment the feedwater heat up
3 that approaches the 440 degrees or so when it
4 ultimately is arriving at the steam generators. So
5 it takes a portion of the energy from the turbine
6 cycle and uses that to preheat the steam and the
7 shelf tube arrangement.
8 And that's the basics of it. If there's
9 any questions, please ask.
10 DR. BANERJEE: Is the steam wet at this
11 point?
12 MR. STORLIS: Yes. Yes.
13 DR. BANERJEE: What's the quality?
14 MR. STORLIS: Without having the curves
15 and the diagram in front of me, I can't speak to
16 that, that specific quality.
17 MR. KAMMERDINER: Probably some in the
18 90s.
19 MEMBER WALLIS: Pretty high.
20 MR. TESTA: This is Mike Testa.
21 We have a heat balance diagram, maybe
22 that would help.
23 DR. BANERJEE: Does it show quality at
24 various points, extraction points?
25 MEMBER SIEBER: That chart would work.

1 DR. BANERJEE: I can't do it in my head.
2 MEMBER WALLIS: And the problem is the
3 wetness, presumably.
4 DR. BANERJEE: Yes, the wetness.
5 MEMBER WALLIS: But it's a few percent.
6 It's not a humongous amount or is it designed to
7 extract in a way that it separates the wall, and it
8 would be wetter, wouldn't it?
9 MR. GRABSKI: Actually the steam quality
10 is fairly low.
11 MEMBER WALLIS: That's in the turbine.
12 But when you extract, don't you sort of have
13 something that's centrifugally separates or anything
14 like that?
15 MR. GRABSKI: We have steam traps and
16 orifices to pull off the moisture.
17 MEMBER WALLIS: It's an oxidate or
18 whatever it is that comes out, ends up in some
19 condensate -- where does it go?
20 MR. GRABSKI: It varies with the system
21 that might be wearing. If you're feedwater's
22 wearing, you're going to get it in the steam
23 generators on secondary side. A lot of the heater
24 drains go to a receiver tank.
25 MEMBER WALLIS: The crude appears in the

1 steam generator. Where does the stuff that's worn
2 away from the pipe?
3 MR. GRABSKI: Again, depending on what
4 system it's in. The heat drains, there's a heat
5 drain receiver tank that it could filter out at. We
6 do have -- do you have something?
7 MR. HANLEY: Yes. Norm Hanley from
8 Stone & Webster.
9 All the secondary side condensate and
10 extraction steam heater drains all recovered. Some
11 of it cascades back to the condenser, some of it's
12 pumped forward to the feed pump suction. So it is
13 all recovered.
14 MEMBER WALLIS: Isn't a lot of it
15 dissolved and then it appears somewhere else in an--
16 MEMBER SIEBER: Heater drain and steam
17 generator.
18 MEMBER WALLIS: In these steam
19 generator?
20 MEMBER SIEBER: Yes. There is a blow
21 down line on the steam generator.
22 MR. HANLEY: Right. There's a blow down
23 in the steam generator. They also sample the
24 secondary side.
25 MEMBER MAYNARD: Well, do you have

1 condensate polishers? Do you run it through --

2 MEMBER SIEBER: Only on Unit 2.

3 MEMBER MAYNARD: Only on Unit 2.

4 CHAIRMAN DENNING: Can you comment on

5 the accuracy of CHECWORKS? I mean, obviously, it's

6 not the four significant figures that's in that

7 table.

8 MR. GRABSKI: Basically the models will

9 improve with the number of examinations you do on

10 the system. It correlates with the data you have.

11 So without any data, I would take it as just a

12 ranking. And that's what we use it for, as a

13 ranking. But actually in our extraction steam which

14 we examine the heck out of, they actually correlate

15 pretty well once you get enough data in there.

16 MEMBER MAYNARD: I take it you also use

17 industry experience what's found at other places --

18 MR. GRABSKI: Oh, absolutely. Our

19 examinations are the backbone. But certainly ops

20 experience, trending of data at our plants and then

21 that's all factored in.

22 DR. BANERJEE: Is there any increased

23 erosion due to the wet steam, the velocities being

24 somewhat higher or --

25 MR. GRABSKI: Yes. That's in the

1 CHECWORKS algorithm higher velocity results in a
2 higher wear rate.
3 DR. BANERJEE: Due to erosion or is it
4 some erosion/corrosion?
5 MEMBER WALLIS: I suspect it includes
6 both erosion --
7 MR. GRABSKI: The FAC takes in the both.
8 That's the mechanism.
9 DR. BANERJEE: But does it also depend--
10 does this depend on the wetness as well?
11 MR. GRABSKI: Absolutely. That's a
12 factor in the algorithm.
13 DR. BANERJEE: You feed this stuff into
14 CHECWORKS and out comes these numbers?
15 MR. GRABSKI: Yes.
16 DR. BANERJEE: Hopefully.
17 MR. GRABSKI: Hopefully, yes.
18 DR. BANERJEE: Yes. Who developed this
19 thing?
20 MR. GRABSKI: EPRI developed CHECWORKS.
21 And it's the industry --
22 DR. BANERJEE: Probably validated
23 against data?
24 MR. GRABSKI: They call it an empirical
25 study --

1 DR. BANERJEE: I see.

2 MR. GRABSKI: -- based on lab and actual

3 events in the industry.

4 MEMBER KRESS: There's sort of a

5 Bayesian update. You go in and inspect and you

6 compare the inspection findings, and then you adjust

7 CHECWORKS to better agree with your findings?

8 MEMBER WALLIS: Learns about your --

9 MEMBER SIEBER: Putting your own data --

10 MR. GRABSKI: Exactly. As I said, they

11 call it a pass one without any data. Once you get

12 enough data in there, it correlates itself. And you

13 have a line correlation factor, it's called.

14 DR. BANERJEE: So the predicative

15 capability is always in question of these types of

16 things? It's only as good as your database?

17 MEMBER SIEBER: By the time you are

18 ready to decommission the plant, it will be very --

19 DR. BANERJEE: Yes, it'll be excellent

20 by them.

21 MEMBER KRESS: Or by the time you're

22 ready for a license extension.

23 DR. BANERJEE: Extrapolation is always

24 dangers in these sorts of things. There's no theory

25 or model there, right?

1 MR. GRABSKI: Well though EPRI calls it
2 a model and it certainly does take into
3 consideration velocity, temperature --
4 MEMBER MAYNARD: And geometry, right?
5 MR. GRABSKI: And geometry. Exactly.
6 But again, it's as good as the data you're putting
7 into it at the point.
8 DR. BANERJEE: Let's imagine that we
9 take this today with the data you've got and try to
10 predict what will happen two years from now. Has it
11 ever been tested in this mode to show whether it
12 gives a reasonable prediction?
13 MR. GRABSKI: Yes, I think it has.
14 DR. BANERJEE: It does?
15 MR. GRABSKI: Yes, it does. It
16 certainly. Yes. It'll give you --
17 MEMBER MAYNARD: Isn't the main purpose
18 of it, though, to predict areas where you may have
19 high wear rates and that you inspect those and that
20 you put those in your trending program? And you're
21 actually using more actual trend data than you are a
22 prediction from the program as to when that line
23 might break?
24 MR. GRABSKI: Exactly. It gives you the
25 places to look first. The highest susceptible line.

1 And I think it does a very good job of that. But
2 once you get into a qualitative or quantitative
3 measure, that's when you need to get some data in
4 there to verify what the model is telling you.
5 You may be right on the money, but again
6 once you get more and more data in there, you
7 correlate the model and then it becomes a very good
8 predictive tool.
9 MEMBER MAYNARD: Yes. Most of the plants
10 do a lot of measuring of a large number of areas
11 where they measure and periodically do that so they
12 can see what's trending.
13 MR. GRABSKI: Exactly.
14 MEMBER MAYNARD: It's not just using a
15 computer program to --
16 MR. GRABSKI: No. Your data proves it,
17 but it's a great start because it's going to tell
18 you that this T is more susceptible than this T,
19 elbow to elbow.
20 MEMBER MAYNARD: But again that's the
21 way the nuclear safety issue other than if it could
22 result in an unnecessary plant transient or it may
23 be a personnel safety, but from a nuclear safety
24 accident it's not.
25 MR. GRABSKI: That's true.

1 MEMBER SIEBER: And if you take a big
2 fitting like an elbow or a T, a single measurement
3 is inadequate. You have to basically put a grid on
4 that fitting.
5 MR. GRABSKI: Right.
6 MEMBER SIEBER: Take a lot of
7 measurements of different positions. Because the
8 wear will be local to someplace where there is an
9 eddy in the flow stream.
10 MR. GRABSKI: That's correct.
11 DR. BANERJEE: Have you seen any erosion
12 in the high pressure stages?
13 MR. GRABSKI: Excuse me?
14 DR. BANERJEE: Did you see any erosion
15 at all in the high pressure stages?
16 MEMBER SIEBER: Main feed?
17 DR. BANERJEE: Yes.
18 MR. GRABSKI: Some feedwater, we have
19 very low wear rates there. In our main steam coming
20 off the steam generators, we haven't seen any wear--
21 DR. BANERJEE: What about the turbine
22 plates, any erosion there, high pressure plates?
23 MR. GRABSKI: I don't know. That's not
24 my expertise on the turbine.
25 MEMBER SIEBER: But generally speaking--

1 DR. BANERJEE: You should have any.

2 MEMBER SIEBER: -- what erosion you see,

3 you see at the very -- the exhaust end of the

4 turbine. And if your moisture separators and

5 everything are working properly, you don't see

6 hardly anything at all.

7 DR. BANERJEE: Not in nuclear plants,

8 but some fossil plants you do because of the oxide--

9 MEMBER SIEBER: Well, generally the

10 fossil plants are better than the nukes because they

11 operate at a higher temperature.

12 MR. GRABSKI: That's true.

13 DR. BANERJEE: Yes. But the oxide flakes

14 come and hit the high pressure stages sometimes,

15 depending on how you cycle the plant. But you don't

16 see any so the higher velocity doesn't give you a

17 problem?

18 MR. GRABSKI: Again, I'm not a turbine

19 guy.

20 DR. BANERJEE: Right.

21 MEMBER WALLIS: It's not a nuclear

22 problem. It's not a nuclear safety problem. Just

23 expensive if you have to fix the turbine.

24 CHAIRMAN DENNING: I think we're

25 completed them, yes?

1 MR. GRABSKI: Yes, unless you have any
2 questions.
3 CHAIRMAN DENNING: I think we're good.
4 Thank you.
5 MR. GRABSKI: Thanks.
6 CHAIRMAN DENNING: And I think NRR now
7 is going to present in the same basic area.
8 MEMBER WALLIS: They're going to defend
9 CHECWORKS, are they?
10 CHAIRMAN DENNING: You can go ahead.
11 MR. SCARBROUGH: Thank you.
12 Good morning. I'm Tom Scarbrough in the
13 Division of Component Integrity of NRR. And with me
14 today is the Branch Chief in Division Engineering,
15 Kamal Manoly and Dr. John Wu.
16 We're going to talk about the
17 engineering mechanics aspects of the review. In
18 terms of the components evaluated, they included the
19 reactor vessel, the internals, the nozzles,
20 supports, control rod drive mechanisms, the steam
21 generator, reactor coolant pumps, the pressurizer
22 and the supports, nuclear steam supply system and
23 balance of plant piping systems and supports and
24 safety related pumps and valves. Motor operated
25 valves, air operated valves and safety relief

1 valves.

2 The scope of the review included the

3 impact of the EPU conditions due to changes in

4 system pressure, temperature and flow rate.

5 The review of the licensee's evaluations

6 of EPU conditions including the analytical

7 methodology, loads, flow-induced vibration,

8 calculated stressed and cumulative fatigue usage

9 factors, acceptance criteria, ASME codes and

10 addenda, functionality impact of EPU on Generic

11 Letter 89-10 for motor operated valves and Generic

12 Letter 95-07 for pressure locking and thermal

13 binding of power operated valves.

14 The license's EPU evaluation does

15 incorporate an improved leak before break criterion

16 that allows elimination of postulated primary loop

17 pipe breaks in the original design basis analysis.

18 And after elimination of the primary coolant loop

19 breaks by the application of the leak before break

20 criterion, the existing design bases analysis for

21 NSSS piping and components are bounded for the EPU

22 evaluation considering postulated smaller branch

23 line pipe breaks.

24 The specific areas where the Staff

25 requested additional information included the main

1 steamline and feedwater line flow-induced vibration
2 due to increased flow rate, quantitative analysis
3 and results for the Beaver Valley Unit 1 replacement
4 steam generator, calculation of cumulative usage
5 factors for the vessel flange closure stubs,
6 considering 10,400 cycles as opposed to the 18,300
7 cycles of the design bases.
8 With respect to flow-induced vibration
9 in particular, the main steamline and feedwater
10 piping are instrumented at critical locations to
11 monitor vibration levels at current rate of power
12 and during power ascension up to full authorized EPU
13 power level. The vibration monitoring and the
14 collective data will be evaluated according to ASME
15 Standard and Guide 2003 Part 3.
16 The flow-induced vibration effect on the
17 steam separators and the steam generators is
18 expected to increase somewhat for EPU conditions.
19 Based on the licensee's response to the request for
20 additional information to the request for additional
21 information, the potential for flow-induced
22 vibration of the steam separator is minimized due to
23 its high stiffness resulting in a high natural
24 frequency combined with a low velocity. And we
25 heard about it, it's about 4 feet per second or so

of passing flow. And past inspection performed for steam generator, moisture separators on operating PWR, pressurized water reactor plants have found no indications due to flow-induced vibration fatigue.

The flow-induced vibration on the U-bend tubing and the steam generators is within allowable limits. In other words, the fluid-elastic instability ratio was maintained less than the limit of 1.0. And peak stresses are less than the material endurance limit.

There were some pump and valve modifications to accommodate the EPU operations. These are relatively minor considering the 7 percent EPU power uprate. The charging and safety injection pumps have been modified to improve their high head performance and flow rate.

The tolerance settings for the main steam and safety valves and reactor coolant pressurizer safety valves have been adjusted.

New trim was installed in the feedwater regulating valves in Beaver Valley Unit 1 and those valves were replaced at Beaver Valley Unit 2.

Fast acting main feedwater isolation valves were installed in Beaver Valley Unit 1 similar to those in Unit 2.

1 And based on the Staff's review our
2 conclusion is that the calculated stresses and
3 accumulate usage factors in the NSSS and balance of
4 plant piping and components are bounded by the
5 original design basis analysis with the application
6 of the leak before break technology, such that the
7 postulated primary loop pipe breaks are eliminated.
8 The potential for flow-induced vibration
9 is not increased for steam separators and the steam
10 generator tubes at EPU conditions.
11 The main steamline and feedwater line
12 piping is monitoring to remain within the allowable
13 limits in accordance with ASME OM3 code guidance.
14 The NRC Staff reviewed the licensee's
15 assessments related to functional performance of
16 safety related valves and pumps at Beaver Valley for
17 EPI conditions and based on that review the licensee
18 has adequately addressed the EPU effects on safety
19 related pumps and valves. And as a result, the
20 Staff concludes that the licensee has demonstrated
21 that the safety related valves and pumps will
22 continue to meet their NRC regulatory requirements
23 during EPU operation at Beaver Valley.
24 So we'd be happy to answer any questions
25 you might have.

1 CHAIRMAN DENNING: I think this is
2 pretty clean. Any questions? Okay. Thank you.
3 MR. SCARBROUGH: Thank you.
4 MEMBER WALLIS: Are we gaining time
5 here?
6 CHAIRMAN DENNING: Oh, yes, we're
7 gaining time.
8 We're going to go ahead with the next
9 presentation.
10 An NRC presentation. By Gregory Makar.
11 MR. MAKER: Good morning. I'm Greg
12 Makar. I am in the Division of Component Integrity.
13 And my branch works on issues of steam generator
14 integrity and other chemical engineering topics.
15 And this morning the Staff reviews in five areas:
16 Low accelerate corrosion, steam generator tube
17 integrity, the steam generator blowdown system,
18 chemical and volume control system and finally
19 coatings.
20 Our review of flow accelerated corrosion
21 begins with determining of the licensee has
22 evaluated the changes due to the extended power
23 uprate on the parameters like temperature, velocity,
24 moisture content that are the keys in controlling
25 flow accelerated corrosion rates. They did this and

1 based on the known effects of this parameters, you
2 see as Mr. Grabski explained, cases where the
3 corrosion rates would be expected to increase and
4 some where it would be expected to decrease.
5 MEMBER WALLIS: The boron content has no
6 effect on any of this?
7 MR. MAKER: Excuse me, boron --
8 MEMBER WALLIS: Boron doesn't seem to be
9 a parameter that comes into this at all?
10 MR. MAKER: No.
11 MEMBER WALLIS: This is simply because
12 it's ignored or because it's proven to have no
13 effect?
14 MR. MAKER: Well, if it changed the pH,
15 say, then if the pH decreased because of it. But as
16 I understand it, the pH does not decrease
17 significantly enough to change the corrosion rate in
18 this case.
19 So to satisfy that they were scoping
20 things in properly, there's also the question of
21 scoping things out because you want to keep your
22 resources focused where they're needed. And there
23 are criteria. And all of these cases we're going
24 primarily by the EPRI guidelines on flow accelerate
25 corrosion programs. That scoping out components

1 based on things like temperature below 200 degree
2 Fahrenheit, the chromium content being 1 and a
3 quarter percent or higher. And this they're doing
4 according to the EPRI guidelines.
5 DR. BANERJEE: Does NRC have any
6 programs which independently check EPRI sort of
7 guidelines and things?
8 MR. MAKER: No. No, computer models or
9 programs.
10 DR. BANERJEE: Even the research
11 programs or whatever?
12 MR. MAKER: No.
13 DR. BANERJEE: How do you know that --
14 do you audit it in some way other than just take
15 their data or what?
16 MR. MAKER: The way that we evaluate
17 this is by -- the NRC in the past was involved in
18 developing a response flow accelerate corrosion and
19 understanding the parameters that are the key
20 influences on it. And I think at that time we did
21 have research programs to determine those. I think
22 we were in the lead at that time and helped lead
23 industry toward a resolution and a development of
24 the computer based programs. And followed and
25 participated in research efforts to understand all

1 the parameters and their influence.

2 DR. BANERJEE: So when did that effort

3 terminate within RES or wherever in NRC it was?

4 MR. MAKER: I'm sorry. I don't know the

5 answer to that.

6 DR. BANERJEE: Was it a long time ago or

7 recently?

8 MR. MAKER: Well, several -- I don't

9 know. And currently we sent -- for example, we send

10 people to training to understand how CHECWORKS is

11 used.

12 DR. BANERJEE: That's an EPRI training?

13 MR. MAKER: Yes. But the effect of

14 these parameters on low accelerated corrosion is

15 fairly well understood now. And I think the most

16 value on making sure the licensees are following

17 these programs and using -- skipping ahead a little

18 bit. But the computer models for plants are one

19 factor. But really the key is actually inspecting

20 systems at repeatable locations and developing data

21 so that you can then trend and determine corrosion

22 rates. That allows you to make decisions about

23 future inspections and replacement repairs. And

24 also it improves the quality, the predictive ability

25 of the model.

1 DR. BANERJEE: Does this apply mainly to
2 components that can be inspected then or there
3 components which inspection is difficult?
4 MR. MAKER: Yes. It should apply to
5 all. There are cases where it's difficult to inspect
6 components. And in that case what the licensees may
7 do is go to a secondary inspection or a testing
8 technique such a radiography, which isn't as good as
9 ultrasonic testing. Or they may have another
10 similar system behaves, is nearby, say, same type
11 environment which behaves in the same way. And
12 they'll use that --
13 DR. BANERJEE: So you're talking mainly
14 of the secondary side rather than the primary side?
15 MR. MAKER: Yes. Yes.
16 DR. BANERJEE: None of this concerns the
17 primary side then? Okay.
18 MEMBER WALLIS: Because of the materials
19 that are used there, is that it, really?
20 MR. MAKER: Well, yes. Once you get to
21 1 and a quarter.
22 MEMBER SIEBER: Single phase flow.
23 MR. MAKER: Yes. And you need moisture
24 fort his to occur.
25 MEMBER WALLIS: Moisture isn't

1 necessary. You've got this in the feedwater line.
2 MR. MAKER: Sorry. Yes.
3 MEMBER WALLIS: I mean --
4 MR. MAKER: And there's also a
5 temperature --
6 MEMBER WALLIS: Okay. I guess --
7 MR. MAKER: Well, some things like
8 velocity, as you increase velocity you would expect
9 corrosion rate to increase. There are other effects
10 like temperature where there's a peak around 300
11 degrees fahrenheit and then beyond that then it
12 start decreasing.
13 MEMBER WALLIS: Well, CHECWORKS is well
14 established, and it's updated from time-to-time. So
15 throughout industry, isn't it? This is why the NRC
16 has stopped --
17 DR. BANERJEE: Also I suppose from a
18 safety point of view this is not incredibly
19 significant.
20 MEMBER WALLIS: Right.
21 MEMBER SIEBER: Not safety related.
22 MEMBER MAYNARD: The NRC does perform
23 periodic inspections at the site on the flow
24 accelerated corrosion program.
25 MEMBER SIEBER: Sure.

1 MEMBER MAYNARD: So it's not something
2 that's just left out.
3 MR. MAKER: Plant audits, yes.
4 MEMBER MAYNARD: Yes.
5 MR. MAKER: So following on that idea,
6 the importance of the inspection, this is really
7 their -- a key to their program is ultrasonic
8 measurements at repeatable locations to develop
9 corrosion trends. And therefore, the combination of
10 the required thickness of the components, the
11 measured thickness and the corrosion rates are the
12 key to future inspections and replacement repair
13 decisions. And the CHECWORKS computer program is
14 one tool in managing this program.
15 Next slide, please.
16 So they are updating the models. I've
17 done that for the EPU. It does predict some
18 increases in corrosion rates in some cases,
19 decreases in others.
20 In cases where there's a large increase,
21 it happened to be a system with a very low corrosion
22 rate to start with. And that was an example Mr.
23 Grabski showed.
24 So considering all these things, we
25 concluded that their program will continue to manage

1 the flow accelerated corrosion effectively after the
2 extended power uprate.
3 Next please.
4 Address steam generator tube inservice
5 inspection. Our guidance here is some -- we have
6 standard review plans on materials and also for
7 inspection we're focused mainly on the NEI 97-06,
8 which also refers to the more detailed EPRI steam
9 generator program guidelines. And as you've heard,
10 the steam generators in Unit 1 were replaced.
11 There are two key materials upgrades;
12 the thermally treated Alloy 690 tubes and also the
13 stainless steal tube support plates, which these two
14 things have a big effect on types of degradation
15 that are observed and the rates of degradation,
16 initiation and propagation. There are also some
17 additional design factors like the shape of the
18 holes in the tube support plates, the type of the
19 antivibration bar design. And all of these are major
20 improvements in steam generators.
21 Now the temperature, and the temperature
22 is one of the key parameters in causing degradation.
23 That will remain within the range seen at other
24 plants that have 690 tubes.
25 There is a possibility, as you

1 discussed, in tube vibration and wear. And there's
2 been an evaluation that the likelihood for wear is
3 low. But for our purposes we're looking at the fact
4 that if there is wear, that is captured in the tube
5 integrity program. That the inspections will see
6 that they're required to evaluate that and monitor
7 that in their operational assessments and their--
8 MEMBER MAYNARD: Has Beaver Valley
9 either made their tech spec changes or committed to
10 make the tech spec changes for the Generic Letter
11 06-01?
12 MR. MAKER: They have an application in
13 house now that being evaluated.
14 MR. KAMMERDINER: If I could add
15 something. This is Greg Kammerdiner from
16 FirstEnergy.
17 We have submitted the license amendment
18 request to adopt TSTF449 for both units.
19 MR. MAKER: So we're concluded for Unit
20 1 that their program will continue to manage
21 degradation at uprate conditions.
22 Next please.
23 For Unit 2 they have the original steam
24 generators with the milled annealed Alloy 600 tubing
25 and both carbon steel and Alloy 600 tube support

1 structures. The existing degradation mechanisms
2 include several forms or several modes of stress
3 corrosion cracking and also some small amount of
4 antivibration bar where the cracking initiation and
5 growth rates could increase based on the small
6 temperature increase and also increases in flow and
7 potentially sludge accumulation at EPU conditions.
8 However, these changes are relatively small and
9 still will remain within the experience we have at
10 other operating plants. And we don't see this as a
11 -- it will not degrade in anyway their ability to
12 monitor, to detect and monitor degradation at uprate
13 conditions.
14 And we also note that these steam
15 generators have a couple of design features,
16 improvements over a lot of the Alloy 600 plants,
17 such as the heat treatment to stress relieve small
18 radius U-bends and also shop pinning in the portion
19 of the tube within the tube sheet. And these are
20 things which are shown to retard the initiation of
21 stress corrosion cracking.
22 The AVB wear rates for Unit 2 are
23 measurable but low. But as with Unit 1, again, there
24 are inspections performed to measure this and
25 evaluate it.

1 We don't expect with these small changes
2 and conditions any new forms of degradation to
3 emerge as a result of the uprate. But, again, we're
4 satisfied that their program will find them and will
5 continue to be consistent with the guidelines at
6 uprate conditions.
7 MEMBER SIEBER: I think one of the big
8 factors is the chemistry control of feedwater. And
9 Beaver 2 should do much better than Beaver 1 because
10 it has a polisher, it has 1 years less life even
11 though the capacity factor is better. And generally
12 there's been good careful control of the chemistry.
13 So I would expect to see lower rates of degradation
14 than Unit 1 experienced through its lifetime.
15 MR. MAKER: Thank you. Yes. The
16 importance of water in chemistry is really
17 important.
18 MEMBER SIEBER: That's the key factor in
19 my opinion
20 MR. MAKER: Next, please.
21 The steam generator blowdown system
22 helps steam generator tube integrity by controlling
23 the quality of the secondary coolant. The blowdown
24 flow rates are not expected to increase as a result
25 of the uprate because they're determined by some

1 parameters that are not going to be effected. There
2 is a repositioning of flow control valves due to
3 decreased pressure. This will reduce the maximum
4 achievable flow rate, but not be require. It will
5 not reduce it below what's required.
6 So we conclude that this will not have
7 an effect on the ability to remove impurities from
8 the blowdown. And we also note here this is a
9 system with potential for flow accelerated corrosion
10 and it is in their FAC program.
11 Next please.
12 Chemical and volume control system.
13 Several functions related to the water inventory and
14 quality for the reactor coolant.
15 The heat exchange temperatures, heat
16 exchangers are one of the key components. There are
17 some slight changes in temperature increases and
18 decreases, but they stay well within the -- well
19 below the design values. And the heat exchanger
20 pressures are not changing as a result of EPU.
21 Boration requirements continue to be
22 met. And letdown flow rates, charging rates and
23 nitrogen-16 delay times are not being affected
24 significantly by this.
25 So, again, according to our Standard

1 Review Plan we concluded that this will be
2 acceptable at EPU conditions.
3 Finally on coatings. Unit 1 coatings
4 were specified according to the ANSI standard.
5 We're evaluating compared to -- we have a Reg. Guide
6 1.54, there are ANSI standards that are called out
7 in that. And we have a Standard Review Plan 6.1.2 on
8 coatings.
9 Unit 1 coatings were specified according
10 to ANSI N101.2. When Unit 2 coatings were
11 specified, we now have the Reg. Guide which also
12 referred to 101.2 as well as the newer ANSI standard
13 on the quality of coatings.
14 And the licensee provided us with their
15 uprate environmental parameters compared to the
16 qualification test values for normal and design
17 bases accidents showing that their bounded by those
18 qualification values. And so we expect no effect on
19 the adhesion or the degradation of those.
20 CHAIRMAN DENNING: I mean if there were
21 any issues here in the painting areas, I don't think
22 they're EPU issues. But I'm just curious, did you
23 talk to management of these units about what the
24 status is of their paints, whether there is
25 observable flaking occurring in areas and potential

1 problems there?

2 MR. MAKER: I didn't as part of the EPU.

3 And I talked to our GSI-191 team members who are

4 evaluating their coatings. Well, the debris issue

5 which includes coatings. But they were not able to

6 tell me the status of coatings yet.

7 CHAIRMAN DENNING: Okay.

8 MEMBER WALLIS: Well, it says coating

9 failures are identified by inspection. I'd be

10 curious to know have there been coating failures.

11 MR. MANOLERAS: Yes. This is Mark

12 Manoleras, Beaver Valley, FENOC.

13 I own the coatings program and the

14 coating engineer works for me. Our containment

15 coatings actually have been in very good shape. If

16 we identify a deficiency, it's put in our corrective

17 action system. It's evaluated by that coating

18 system engineer and then it is repaired.

19 We've had outside people come in and

20 take a look at our coatings in response to the GSI-

21 191 to make sure that what we believe is what the

22 outside experts also believe. And we've gotten very

23 good feedback on that, on our coatings, our

24 containment coatings.

25 MEMBER WALLIS: Have you actually had to

1 replace some coatings?

2 MR. MANOLERAS: We've had to make very

3 minor repairs to some coatings in containment.

4 MEMBER SIEBER: Those are typically

5 scrapes --

6 MR. MANOLERAS: That's correct.

7 MEMBER SIEBER: -- as opposed to force

8 or lack of -- somebody runs a cart into the wall,

9 you can scrape.

10 MR. MANOLERAS: That's correct.

11 MEMBER SIEBER: And you have to repair

12 that.

13 MEMBER WALLIS: So it's that kind of

14 thing rather blistering or --

15 MEMBER WALLIS: Right.

16 MR. MANOLERAS: That is correct.

17 MR. MAKER: Okay. That concludes my

18 presentation unless you have any further questions

19 on these five topics.

20 CHAIRMAN DENNING: I think we don't.

21 And I think Mr. Stubbs could now continue with the

22 next presentation.

23 MR. MAKER: Thank you.

24 MR. STUBBS: Good morning. My name is

25 Angelo Stubbs and I'll be discussing the review of

1 the balance-of-plant systems.

2 Next slide.

3 Okay. In conducting our review we

4 utilized Review Standard RS-001, which is a Review

5 Standard for extended power uprates. And in general

6 our review scope covered the balance-of-plant

7 mechanical systems contained in Matrix 5 of the

8 standard.

9 Scope of the BOP systems included over

10 20 systems, 6 major areas of review, the first of

11 which internal hazards for which reviews were

12 performed for the EPU impact on flood protection,

13 equipment of floor drains, the circulating water

14 system, missile protection, the turbine generator

15 and pipe failures.

16 The second area, fission product control

17 included reviews on the fission product controlling

18 systems in the structure, the main condenser

19 evacuation system and the turbine gland seal system.

20 For the next area, component cooling and

21 decay heat removal we reviewed the spent fuel pool

22 cooling and clean up system, service water system,

23 react water cooling system, ultimate heat sink and

24 auxiliary feedwater system.

25 Next slide.

1 The next area of review balance-of-plant
2 included review of the main steam, main condenser,
3 turbine bypass and consondate and feedwater system.
4 And the final two areas was the waste
5 management system, which included gaseous liquid and
6 solid radwaste and then the emergency diesel fuel
7 oil storage and light loads were also reviewed.
8 In addition to our review of the systems
9 I just mentioned, the staff also reviewed test
10 considerations for certain BOP systems.
11 Next slide.
12 The Staff focused under review of
13 auxiliary systems for which increased heat loads
14 associated with the uprated plant might pose an
15 increased challenge to the systems. The systems
16 included the spent fuel pool coolings, the service
17 water and ultimate heat sinks, auxiliary feedwater
18 system and condensate and feedwater system.
19 In regards to the spent fuel pool
20 cooling system, the Staff determined that the
21 licensing bases evaluation, that is the current
22 licensing bases evaluation which was performed at
23 the power level of 2918 megawatts will be bounding
24 for the EPU plant. But service water system and
25 increasing the heat loads was not to have a

1 significant increase in fact on the system. And
2 they stable within the design temperatures of the
3 system.
4 The Ohio River is the alternate heat
5 sink for both of these plants and this capacity far
6 exceeds the shutdown cooling and accident heat load
7 requirements for the Beaver Valley units. And power
8 uprate doesn't effect the temperature in that water
9 for this.
10 The auxiliary heat water system is a
11 system which required increased flow as a result of
12 EPU at both units. In addition, Unit 1 has undergone
13 a modification to add limiting flow venturies. And
14 I'll discuss the EPU impact on these systems a
15 little later when I address modifications that
16 effected the BOP review.
17 And the condensate and feedwater system,
18 there was minor modifications of the regulating
19 valves. But the licensee evaluation showed that the
20 condensate pumps had sufficient margin to operate at
21 the EPU power and that sufficient flow could be
22 provided to the system.
23 In addition to that the parameters of
24 flow, pressure, temperature parameters will be
25 monitored during the startup so that will help

1 verify the performance also.

2 Next slide.

3 The modification. The modifications made

4 to the balance-of-plant. These are I'd like to talk

5 a little bit about. Take a few minutes to talk

6 about.

7 The first was modifications to the high

8 pressure turbine and the second is a modification to

9 auxiliary feedwater system at Beaver Valley 1.

10 Next slide.

11 Okay. But in the case of the high

12 pressure turbine in both units, the high pressure

13 turbine is being replaced with an all reaction

14 turbine. The Unit 1 modification has already been

15 completed. They have calculated the maximum

16 overspeed to be 118, which is below the acceptance

17 criteria of 120.

18 The Unit 2 modification has not been

19 completed yet and will be completed prior to

20 operation at EPU. But at this time they have done

21 the calculations for overspeed the licensee has

22 committed to perform the appropriate overspeed

23 analysis to ensure overspeed protection that's

24 acceptable. Also as part of their operating

25 surveillance tests verifies that the proper

1 operation of the turbine overspeed trip protection
2 system and that -- and they do this by demonstrating
3 that the turbine works at or below the 111 percent
4 at that.
5 MR. TESTA: Excuse me. This is Mike
6 Testa.
7 I just wanted to clarify one thing for
8 Unit 2. Now the way we're going to -- we're going
9 to do a staged power increase. The existing turbine
10 has additional capacity to it, around 5 percent. So
11 we're going to elect to increase the power somewhat
12 the existing turbine. But prior to going to the full
13 extended uprate, we will replace the turbine with
14 the reaction turbine.
15 MR. STUBBS: Okay. The auxiliary
16 feedwater system, for this system in Unit 1 they're
17 adding cavitating venturies. They're installing that
18 as a modification to Unit 1.
19 At EPU the auxiliary feedwater pumps,
20 which are now being credited for the feedwater line
21 break and the loss of normal feedwater events, which
22 is something that the current plant doesn't do.
23 Unit 2 licensing bases already credits
24 these to AFW pumps. So this isn't a change to Unit
25 2. It's only a change to Unit 1. We did look at

1 that. And the total required flow for the auxiliary
2 feedwater system will be able to be met by any of
3 the two pumps available out of the three that
4 services that system. And there will be sufficient
5 capacity for it to perform this intended function.
6 And the technical specifications, as I
7 just mentioned, requires three alternate auxiliary
8 feed pumps to be operable. And so this allows us to
9 have a single failure and still require it to -- for
10 the two events, the loss of normal feedwater and
11 heat feedwater line break.
12 Next slide.
13 Okay. In summary, Staff finds that the
14 proposed EPU to be acceptable with respect to the
15 balance-of-plant areas based on:
16 The evaluations that was performed that
17 we reviewed;
18 The commitments made by the licensee,
19 and;
20 The tests that they will be performing.
21 So, is there any questions.
22 CHAIRMAN DENNING: Are there any
23 questions? No.
24 Thank you very much.
25 MR. STUBBS: Okay. Thank you.

1 CHAIRMAN DENNING: Now what we'll do is
2 we'll take a 15 minute break so we can prepare
3 ourselves for the risk assessment presentations. And
4 we'll be back by the clock on the wall at 10:00.
5 (Whereupon, at 9:49 a.m. off the record
6 until 10:04 a.m.)
7 CHAIRMAN DENNING: We'll now come back
8 into session. And our first presentation will be on
9 risk analysis and its impact.
10 MR. KELLER: Good morning. My name is
11 Colin Keller. I'm a supervisor of the PRA Group at
12 Beaver Valley.
13 With me here today also is Bill Etzel to
14 help answer any questions that the Subcommittee may
15 have.
16 A little bit about myself. I've been in
17 nuclear power for 24 years now at Beaver Valley,
18 starting at the Shippingport Atomic Power Station
19 and working through other engineering assignments
20 through Unit 2 startup, equipment qualification and
21 the last ten years I've been involved in PRA.
22 I'm here today to discuss the Beaver Valley
23 EPU PRA models, one for each unit.
24 Next side.
25 And I'd like to talk about the elements

1 of the Beaver Valley model that were reviewed as
2 part for this uprate. And also to talk about the
3 resulting changes in core damage from these reviews.
4 Next slide.
5 The first element we reviewed was our
6 initiating events. We found that from the extended
7 power uprate there were no new initiators identified
8 and also there were no significant increases in our
9 initiating event frequencies as a result of the
10 power uprate.
11 We also did a review of our success
12 criteria. We used the MAAP code to perform these
13 analyses to establish our success criteria. Also
14 included setpoint changes in there due to
15 containment conversion and new pump curves that were
16 put in.
17 We found that new accident sequences
18 were identified as a result of the power uprate.
19 We went on to review our component and
20 system reliability. Comprehensive reviews of the
21 equipment were performed. We found that systems
22 will operate within their allowable limits. There
23 was on the PRA failure rates or results. We will
24 continue to use our existing monitoring programs to
25 account for any additional system wear using

1 Maintenance Rule MSPI, flow accelerate corrosion.
2 We expect that our future model updates
3 will capture any initiating event or equipment
4 failure rate changes.
5 We also performed reviews of our
6 operator response times for our human reliability
7 analysis. The MAAP analysis was used to determine
8 operator action times that are available. Higher
9 decay heat did reduce times for some of these
10 operator actions.
11 The most important impacts were:
12 For operators to start aux feedwater
13 given a solid state system protection has failed and
14 no SI signal present;
15 Operator initiates a bleed and feed,
16 and;
17 And there was a reduction in time to
18 recover from a loss of shutdown cooling due to
19 reduced inventory.
20 This is a listing of Unit 1's five most
21 important operator actions. You see there was a
22 reduction in time for two of those actions from the
23 pre-EPU to the post-EPU. And as a result of that,
24 there was also an increase in their human error
25 probability for both of those actions.

1 The following table --

2 CHAIRMAN DENNING: No. Let's stick a

3 little bit with this. You were done with this

4 table, let's spend a little bit more time on the

5 table.

6 MR. KELLER: Certainly.

7 CHAIRMAN DENNING: So the first item and

8 the last time are the only ones where you have a

9 significant change in your human error rates, is

10 that right?

11 MR. KELLER: Yes. And as you can see,

12 those are also the ones that saw a reduction in

13 operator action time.

14 CHAIRMAN DENNING: Now this initiating

15 feed and bleed, there's really a major time,

16 difference in time, isn't there? Between 78 minutes

17 and 29 minutes, is that right?

18 MR. KELLER: That's correct.

19 MR. ETZEL: This is Bill Etzel from

20 FENOC.

21 Yes. In the pre-EPU case that was done

22 with a hand calculation and it was based on steam

23 generator dryout. For post-EPU feed and bleed was

24 based on a 13 percent wide range level in the steam

25 generators.

1 CHAIRMAN DENNING: So the big difference
2 is really a matter of --
3 MR. ETZEL: Yes, in setpoint levels.
4 CHAIRMAN DENNING: Okay. Now I'd like
5 to spend just a little bit of time on each of these,
6 if you would. And give us some -- and that doesn't
7 necessarily have to be a lot. But let's start with
8 the first one here.
9 The first is starting the auxiliary
10 feedwater system when you have no safety injection.
11 And it does look like the 43 minutes certainly seems
12 a substantial period of time to be available for
13 that. You say the confirmation as it was simulator
14 observation. So tabletop and simulator observations.
15 So you've run through this in the simulator at post-
16 EPU conditions?
17 MR. KELLER: That's correct. And George
18 Storlis is here. He will speak to that.
19 MR. STORLIS: Yes, I'll speak. My name
20 is George Storlis. I'm with FENOC.
21 And operationally we train extensively
22 in the simulator environment. Both Unit 1 and Unit
23 2 have separate simulators, have a lot of exposure
24 to simulator time.
25 One of the key elements of any failure

1 of solid state is manual backup by the operator and
2 the supervisors that stand behind the team as part
3 of the simulation. And 43 minutes is an extensive
4 period of time, as you pointed out, for diagnosing a
5 failure and then ultimately responding to that
6 failure with manual actions. So I'm quite confident
7 that we can make that 43 minutes.
8 CHAIRMAN DENNING: Okay.
9 MR. STORLIS: Probably in the realm of 2
10 minutes or less.
11 CHAIRMAN DENNING: Although you did have
12 a big change in the human error -- I mean a big
13 change in the human error probability. But I won't
14 get into the details of that. I don't care.
15 Now let's look at, the second one
16 obviously that's not an issue is the 24 hours.
17 The next is this portable diesel driven
18 fans to cool the emergency switchgear rooms.
19 MR. STORLIS: Switchgear ventilation
20 affords a rather large heat sink in that area. The
21 portable ventilation is established to enhance
22 existing cooling. And in the absence of cooling you
23 have a period of time to set up and establish that
24 flow.
25 MEMBER MAYNARD: Is the equipment pre-

1 staged?

2 MR. STORLIS: The equipment is available

3 and staged in a brigade area. And it's available.

4 CHAIRMAN DENNING: What about this, this

5 fourth one? Can you describe that one to me? The

6 reactor coolant pump trip, what's happening here.

7 MR. ETZEL: This is Bill Etzel from

8 FENOC again.

9 Yes. That's just a simple reactor

10 coolant pump trip on CCW, which is our component

11 cooling water. And component cooling water supports

12 thermal barrier cooling along with motor and cooling

13 to the motors of the pumps, the reactor cooling

14 pumps. So therefore we assumed that you have five

15 minutes to trip the pumps with that, otherwise you

16 would get an increased RCP seal LOCA due to high

17 vibration.

18 MR. STORLIS: Again, this is an area

19 where operator training is repeated over and over

20 and over again to identify the absence of cooling

21 water flows to the coolant pumps and the need for

22 the five minute window to shut the pumps off to

23 preserve the pump's condition.

24 MEMBER SIEBER: It seems to me you

25 actually had an event like that at one time. Is that

1 correct? Where you lost seal coolant?

2 MR. STORLIS: We did have an event where

3 in loss of an emergency bus did transcend itself

4 into a loss of thermal barrier cooling. And the

5 pump was managed immediate to that and seal

6 injection was reapplied in the pump.

7 MEMBER SIEBER: You actually didn't trip

8 the pump, you reestablished the flow?

9 MR. STORLIS: Seal injection, that is

10 correct.

11 MEMBER MAYNARD: This is I think a

12 pretty common requirement or guideline for all the

13 Westinghouse --

14 MR. STORLIS: That is a true statement,

15 sir.

16 MEMBER MAYNARD: -- seals.

17 CHAIRMAN DENNING: Let's go to the next

18 table them.

19 MR. KELLER: Okay. The next table is

20 similar and is a listing of the operator actions for

21 the Unit 2.

22 CHAIRMAN DENNING: Okay. Let's see, are

23 there any here that are particularly -- okay. Well,

24 let's start at the bottom one, the -- let's see.

25 This is manual trip after the solid state protection

1 system fails to automatically actuate reactor trip.
2 So this is --
3 MR. KELLER: Directly from the bench
4 port.
5 MR. STORLIS: Again, this is George
6 Storlis.
7 The operator identifying conditions as
8 displayed on what we call our first op panel. It
9 enables early diagnoses of the need for trip along
10 with a validation with the existing instrumentation.
11 And the operator's license responsibility and legal
12 responsibility to bring that reactor off line on
13 manual action.
14 CHAIRMAN DENNING: Okay. Let's see --
15 MEMBER KRESS: Did you use a human error
16 model to get these probabilities?
17 MR. KELLER: Yes. We were using the HRA
18 Calculator?
19 MEMBER KRESS: HRA Calculator. That's
20 the EPRI --
21 MR. KELLER: That is correct.
22 MR. ETZEL: We just switched to the HRA
23 Calculator.
24 Bill Etzel, FENOC.
25 When we did this analysis we used the

1 SLIM methodology, success likelihood index
2 methodology.
3 CHAIRMAN DENNING: Let's see --
4 MEMBER KRESS: And the confirmation with
5 the simulators tabletop was just to show that you
6 did it within that.
7 MR. KELLER: Ensure that we would be
8 capable of performing those actions with the times
9 that we don't have.
10 CHAIRMAN DENNING: Now why do you say
11 tabletop there and simulator? Isn't this something
12 that you would have verified with the simulator,
13 validated with the simulator.
14 MR. ETZEL: This is Bill Etzel from
15 FENOC again.
16 Yes. We were going through an update on
17 our PRA model at Unit 1. And like Colin said, we
18 were using the HRA Calculator. So we waned to --
19 since we were changing methodologies, we wanted to
20 validated all our human actions. So we had simulator
21 runs for the Unit 1 PRA model update. Similarly,
22 when we go through the Unit 2 update sometime later
23 this year, we will also do some simulator
24 benchmarks.
25 MEMBER MAYNARD: But many of these are

1 things that you're doing as part of normal ops
2 training anyway, aren't you?
3 MR. STORLIS: That is correct, sir.
4 MEMBER MAYNARD: This last one in
5 particular, that's one of the first things you do
6 when you have an issue is to check it and there's
7 more than one person doing that, too.
8 MR. STORLIS: And that is absolutely
9 correct. We're practiced on these in the simulator
10 environment repeatedly.
11 MR. SENA: Again, this is Pete Sena.
12 The indications available to the operators at Unit 1
13 to take the actions such as manually tripping the
14 reactor in the event of a first out indication for
15 the need for a trip is virtually identical at Unit
16 2. So the actions are the same, the training is the
17 same and the indications are the same. So you can
18 translate the simulation walkthrough that we've done
19 at Unit 1 into Unit 2 through the tabletop method
20 and be confident that the times are identical.
21 CHAIRMAN DENNING: Yes. It is
22 interesting, though, that you seem to have some
23 significant differences between the two units as to
24 what the risk important operator actions are, or am
25 I misinterpreting the similarities here? Is that

1 true?

2 MR. KELLER: There are some differences

3 between the units, yes.

4 MEMBER WALLIS: These are all errors of

5 omission where the operator fails to do something?

6 MR. KELLER: That's the probability that

7 we've failed to accomplish that action.

8 MEMBER WALLIS: Do you somehow put in

9 potential errors of commission by misdiagnosing

10 something and doing the wrong thing? Does that

11 appear in your PRA at all.

12 MR. ETZEL: This is Bill Etzel from

13 FENOC.

14 Mostly they are failures of omission in

15 that he does not perform this action as opposed to

16 doing the wrong action and making things worse.

17 MEMBER WALLIS: Are there some items of

18 commission that would be affected in some way by the

19 power uprate in that there will be a little more

20 going on or more likelihood to make a mistake or

21 something like that? I don't know you assess that,

22 but conceivably in could be a context which is more

23 likely to produce an error.

24 MR. ETZEL: Yes. This is Bill Etzel

25 again.

1 That's a possibility and hopefully
2 through the simulator training and just normal time
3 in the control room will help prevent that.
4 MEMBER WALLIS: Fix that up during
5 simulated training. You observe and see if as a
6 result of the EPU there's more tendency to make some
7 mistake, and then you correct that in some way? Is
8 that the way you find it? You do it by training in
9 the simulator?
10 MR. ETZEL: Yes.
11 MR. STORLIS: And this is George
12 Storlis.
13 With regards to the structure of the OP,
14 operating procedures, the team concept in the
15 control environment, the identification of a
16 potential error being made is identified and
17 corrected before the committing of the act. So from
18 an operating perspective the confidence in the team,
19 the confidence in the training, the confidence in
20 the practice of simulation and EOP network provide a
21 high level of assuredness of proper actions.
22 MEMBER MAYNARD: The EOPs are also
23 fairly good that even if a mistake is made or
24 there's multiple things going on, getting you back,
25 prioritizing and taking care of the issues.

1 MR. STORLIS: That's correct. The
2 response not obtained columns and so forth that
3 structure a pathway to success is very high.
4 CHAIRMAN DENNING: And I think if you
5 identified in your simulator training a place where
6 people were making errors of commission, then you'd
7 correct something rather than putting it as a
8 probability failure in a PRA.
9 MR. KELLER: That's correct.
10 CHAIRMAN DENNING: So it's hard to
11 identify them, Once you do, then presumably you'll
12 fix them.
13 MR. KELLER: Yes. You want to reenforce
14 the training so we would make sure that we'd meet
15 these times.
16 MR. STORLIS: Either in robust barriers
17 and the like to assure that if there is a likely
18 error condition that it's remedied either by
19 physical barrier or other means.
20 CHAIRMAN DENNING: Okay. Proceed.
21 MR. KELLER: Okay. Thank you.
22 Next slide.
23 In regards to the operator response
24 times, we did do a validation of the operator times
25 to complete these actions through combinations of

1 tabletops, discussions of simulator training or
2 observations. And the operator actions with small
3 amounts of time available can be performed within
4 the time that is available.
5 MEMBER WALLIS: "Can" is a big --
6 MR. KELLER: I'm sorry?
7 MEMBER WALLIS: "Can" is a big word. I
8 mean can with probability of zero or one? You think
9 it can be performed with high probability or
10 something.
11 CHAIRMAN DENNING: Well, he has exactly
12 the probabilities on this table.
13 MEMBER WALLIS: He does, I know. But --
14 CHAIRMAN DENNING: These are three
15 significant figures.
16 MEMBER WALLIS: I know. So it's really
17 it will be performed or likely to be performed.
18 MR. KELLER: Likely to be performed.
19 That's probably yes.
20 MEMBER WALLIS: Right. There's some
21 things I can do, but without much probability.
22 CHAIRMAN DENNING: Likely would be a
23 very PRA term.
24 MR. KELLER: I understand. Likely to be
25 performed.

1 Next slide.

2 We also did a review for shutdown risk

3 conditions. We found the EPU has no unique or

4 significant impacts to the shutdown risk. There'll

5 be no changes to shutdown operations to our safe

6 shutdown risk assessments.

7 Next slide.

8 Summary for Unit 1 is shown here for the

9 total core damages from pre-EPU to post-EPU and with

10 a breakdown of internals, externals and fire and

11 also it shows the differences for the total LERF.

12 And the changes in risk are well within the guidance

13 provided by Reg. Guide 1.174.

14 MEMBER MAYNARD: One new piece of

15 equipment that you put in was the main feed

16 isolation valves, How was that treated? Did that

17 end up with positive credit, negative credit

18 relative to the PRA. Because a new piece of

19 equipment --

20 MR. KELLER: Yes. You do have some

21 additional failure probabilities with that and also

22 with the cavitating venturies. There is a

23 probability that they could plug. But overall for

24 the sequences, and Bill correct me, where main

25 feedwater was involved there was not a huge impact

1 from those additional failure rates.

2 MR. ETZEL: That is correct.

3 MEMBER MAYNARD: On the main feed

4 isolation valves are you using an existing design

5 that's been out there proven or is this --

6 MR. ETZEL: This is Bill Etzel from

7 FENOC.

8 We have these similar valves installed

9 at Unit 2, so we use their failure rates and apply

10 them to Unit 1.

11 CHAIRMAN DENNING: Now let me ask an

12 embarrassing question.

13 MR. KELLER: Yes, sir.

14 CHAIRMAN DENNING: Maybe an embarrassing

15 question. And that is, you know, we recognize that

16 there are changes in risks that aren't quantified by

17 the way we treat CDF and LERF, particularly as far

18 as radionuclide inventory is concerned. I mean, the

19 risk is going to increase with no changes in CDF and

20 LEFT, you're going to see there is a true increase

21 in risk of at least a percent associated with --

22 MEMBER KRESS: Sixteen percent.

23 CHAIRMAN DENNING: -- this.

24 MEMBER KRESS: Two plants.

25 CHAIRMAN DENNING: Two plants. Well, I'm

1 not sure that that's still eight percent per, Tom.
2 But in any event, we have had other applicants who
3 have said okay, we want to make sure that the risk
4 is not increased, and so we look to see what aspects
5 of our PRA indicate things that we could fix that
6 would actually reduce the risk or maintain the risk.
7 And I realize, of course, you changed
8 the generator on Unit 1 and there's been probably a
9 decreased risk associated with that. But as far as
10 just looking at the major contributors to risk and
11 recognizing the potential benefit that's associated
12 here that certainly is worth doing, but did you look
13 to see are there things that at this particular time
14 we might change so that indeed we're not increasing
15 the risk?
16 MR. KELLER: Yes. We have looked and we
17 actually have some recommendations based on that.
18 We've looked at things like potentially going out
19 and adding additional methods for RCP seal
20 injection. There was a recommendation also to, I
21 believe it was restructure an EOP to gain some
22 benefit towards large early release frequency.
23 And, Bill, there were two other
24 modifications for each unit we were also looking at?
25 MR. ETZEL: This is Bill Etzel from

1 FENOC.

2 Yes. We also looked at increasing

3 seismic ruggedness. We have at Unit 1 block walls

4 on our emergency batteries. So we're looking at

5 increasing seismic readiness of those block walls.

6 Also putting some fire barriers around

7 our HVAC fans in the cable vault and spreading area.

8 CHAIRMAN DENNING: And has management

9 agreed to any of these upgrades or made a commitment

10 to these at this time?

11 MR. KELLER: At this time our plans to

12 take those to our plant health committee at site and

13 to get them evaluated and go forward from there.

14 See if they'd --

15 CHAIRMAN DENNING: What's the committee

16 you said?

17 MR. KELLER: Called the plant health

18 committee.

19 CHAIRMAN DENNING: Plant health

20 committee?

21 MR. MANOLERAS: Yes. This is Mark

22 Manoleras from FENOC.

23 Our plant health committee is comprised

24 of basically the management team at the site. Each

25 project is presented to the plant health committee

1 and it's weighed on its benefit and risks to the
2 station and then will be implemented in course;
3 ranked and implemented in course.
4 CHAIRMAN DENNING: Yes.
5 MR. ETZEL: And this is Bill Etzel from
6 FENOC.
7 We did present the alternate RCPC seal
8 injection system to the plant health committee
9 already.
10 CHAIRMAN DENNING: And has a decision
11 been made on that at this point or is that --
12 MR. ETZEL: Yes. We have had positive
13 feedback on it.
14 CHAIRMAN DENNING: Yes.
15 MR. KELLER: A decision was made whether
16 to go and install it at this time.
17 MR. ETZEL: Yes. The decision was made
18 was that we were going to take a look at options to
19 actually implement those options and then estimates
20 will be performed on those options. We will go to
21 our next committee, which is our technical oversight
22 committee, which takes a look at the technical
23 robustness of the options and how those will be
24 implemented.
25 So it's well along in the process to be

1 targeted.

2 CHAIRMAN DENNING: What are the criteria

3 that the committee uses to decide whether they would

4 undertake a safety improvement that effectively

5 isn't providing economic benefit?

6 MR. ETZEL: Yes. We actually have a

7 very detailed rating system. We went out and

8 benchmarked the industry and took a look at

9 basically industry best practice. And actually one

10 of the significant contributors to identify a

11 project selection would be an increase or decrease

12 in risk. We actually have a very large portion of

13 our process will actually look at the change in CDF.

14 So it's actually a big contributor to selecting a

15 project to be implemented.

16 CHAIRMAN DENNING: You know, that still

17 didn't help me very much. I mean, I'm talking about

18 some things here where there's no economic benefit

19 to the plant, or at least the economic benefit isn't

20 obvious of some of these safety related improvements

21 that could reduce risk. And so the question is

22 under what conditions would the plant management

23 say, well, it really -- I'm willing to invest some

24 money here to reduce the risk even though I'm not

25 going to see an economic payback and there's no

1 regulatory requirements.

2 MR. ETZEL: Yes. I'm sorry if I didn't

3 answer that clearly. A reduction in that risk is

4 one of the key contributors to ranking a project.

5 It is probably one of the top three contributors to

6 ranking a project.

7 CHAIRMAN DENNING: Thank you.

8 MEMBER KRESS: As a bit of a follow on

9 to this question, does your PRA system have the

10 capability to do a level 3 analysis?

11 MR. ETZEL: This is Bill Etzel again.

12 Currently we do not. We just have level

13 1 and level 2.

14 MEMBER WALLIS: With a follow up

15 question again. I understand that management looks

16 at decreasing risk as a criterion for endorsing a

17 project. Presumably there's something on the other

18 side of the balance which is the cost of

19 implementing this. And I just wonder how much your

20 management is willing to pay? Do they have some

21 sort of a figure that says we're willing to pay so

22 much for so much decrease in risk? Is there some

23 kind of an economic that's understood in the plant

24 or is it not? You don't have to give me the

25 figures, but it seems to me in the end its cost

1 benefit that's got to rule in the decision.

2 MR. SENA: This is Pete Sena.

3 When we go through the plant health

4 committee there's a detailed ranking form, as Mark

5 was speaking towards, as far as how we score a

6 particular project. Some of the other criteria may

7 be, for example, does the modification result in in

8 improvement in radiation dose to folks doing work on

9 the station. Other criteria would be, you know, a

10 change in personal safety, a change in equipment

11 reliability. So there are many factors.

12 Those factors are then accumulated and

13 tabulated. And that is then weighed against all the

14 other modifications that are proposed.

15 Now, out of a year we will go through

16 and we will pick, perhaps, our top 12 or 15 projects

17 to go implement to look a year ahead. But, again,

18 we do have limited financial means, as every other

19 utility does. So we have a specific set budget. But

20 the ranking criteria does not apply to the initial

21 cost estimate. It would then be categorized against

22 all the other mods. And we have X number of dollars

23 and how many mods do we want to do with that X

24 number of dollars.

25 MEMBER WALLIS: And so you have to spend

1 your budget?

2 MR. SENA: We would spend our budget,

3 correct.

4 MEMBER WALLIS: So there is no trade-

5 off? It's just a question of which ones do you

6 spend it on, is that it? That was an interesting

7 economic viewpoint.

8 MR. SENA: Well, again --

9 MR. MANOLERAS: Well --

10 MR. SENA: Go ahead.

11 MR. MANOLERAS: This is Mark.

12 Again, we want to weigh all the factors

13 for the selection of this modification. We may want

14 to increase equipment reliability in an area, we may

15 want to increase personal safety. So we do weigh all

16 those facets when we select the modification

17 packages.

18 MEMBER KRESS: Just out of curiosity,

19 how far away is Pittsburgh from Beaver Valley's

20 plant?

21 MR. MANOLERAS: It's approximately 30

22 miles.

23 MEMBER KRESS: Thirty miles?

24 MR. MANOLERAS: That's correct.

25 CHAIRMAN DENNING: Proceed.

1 MR. KELLER: Thank you.

2 The next slide is a similar summary for

3 Unit 2 showing the same changes. And, again, the

4 changes in risk for both CDF and LERF are below the

5 thresholds for Reg. Guide 1.174.

6 MEMBER WALLIS: Reg. Guide 1.174 also

7 gives you no incentive decreased risk.

8 MR. SENA: And, Dr. Wallis, if I may

9 just go back to how we look at various projects we

10 may do. One example to speak towards, for example,

11 is we installed N16 monitors at Unit 2. We had them

12 previously installed at Unit 1. But, again, this was

13 a benefit to the station. Not a production benefit,

14 but a safety benefit so that operators would have a

15 key prompt indication of a potential tube leak. So,

16 again, that is an excellent example of a mod that

17 met our criteria to move forward with.

18 MEMBER WALLIS: Thank you.

19 CHAIRMAN DENNING: Yes?

20 MR. KELLER: Okay. And summary, all the

21 PRA model elements were reviewed for impact and

22 found that the increase in risk due to the EPU for

23 both Unit 1 and Unit 2 does meet the acceptance

24 criteria. There were small changes in operator

25 times that were available for some actions, and

1 additional equipment that was installed had a small
2 impact on overall risk.
3 CHAIRMAN DENNING: Let me just state for
4 the record, I mean I think it's fine for you to
5 compare with Reg. Guide 1.174, but its applicability
6 to power uprates is somewhat questionable. And I
7 think that the way the risk analysis was used in the
8 review is really in a slightly different way than
9 applies 1.174 to a change in the licensing.
10 MR. KELLER: Since it's not a risk
11 informed application?
12 CHAIRMAN DENNING: Right.
13 MR. KELLER: Okay. I understand.
14 CHAIRMAN DENNING: Well, not to say that
15 it isn't interesting to look at.
16 MEMBER SIEBER: It's not a risk informed
17 application. It's nice to have risk information.
18 CHAIRMAN DENNING: Right.
19 MEMBER SIEBER: And, for example, the
20 PRAs the state of the art today, does not evaluate
21 and assign risk numbers to how much margin that
22 you're reducing.
23 CHAIRMAN DENNING: Right.
24 MEMBER SIEBER: And to me that's a
25 significant thing, but we are not going to easily

1 get to the point to do that. It's a tremendous
2 amount of work. And that's probably off in the
3 future in number of years.
4 MR. KELLER: That's all I have.
5 MEMBER WALLIS: Do you have some
6 perspective on what's the effect of these power
7 uprate on risk? I mean, this is a measure of safety
8 and this is what we're here for, so we get some idea
9 what are the consequences of an EPU. And I think
10 that's useful. But it's not as if 1.174 is the rule
11 that you're going to use.
12 MR. KELLER: Oh, agreed. But it is a
13 measuring stick, yes.
14 MEMBER WALLIS: Yes.
15 MR. KELLER: Any other questions?
16 CHAIRMAN DENNING: Okay. I see no other
17 questions. I think we're ready to move on to the
18 staff.
19 MR. KELLER: Thank you.
20 CHAIRMAN DENNING: Thank you.
21 We're on the Staff's presentation on
22 risk assessment.
23 MEMBER SIEBER: Risk evaluation.
24 MR. LAUR: Well, good morning. I'm glad
25 to see it's still morning.

1 My name is Steve Laur. I'm in the NRR
2 Division of Risk Assessment, Senior Reliability &
3 Risk Analyst. I'm here today to discuss the Staff
4 review of the Beaver Valley EPU risk assessment.
5 Next slide.
6 I'll give you the conclusion slide first
7 and if that's all you want to hear, we can make this
8 even shorter.
9 The licensee assessed the potential risk
10 impacts of the extended power uprate. Our review
11 concluded and agreed with the licensee that special
12 circumstances do not exist that would rebut the
13 presumption of adequate protection. So therefore,
14 we have approved going forward with this proposed
15 power uprate.
16 Next slide.
17 Just a reminder, I think you just
18 mentioned this right before I got up here, but they
19 are not risk-informed as defined in Reg. Guide
20 1.174. However, there is an applicable review
21 standard 001 that basically describes the purpose
22 for the risk information that the licensee provides.
23 First of all, to determine whether the
24 risk is acceptable. But as I mentioned before, to
25 determine special circumstances exist that would

1 rebut the presumption of adequate protection
2 afforded by compliance with regulations. And this
3 is discussed in the Standard Review Plan, Chapter
4 19.
5 This has been said a few times yesterday
6 and today, but I want to reiterate this. This is an
7 8 percent power uprate. The Staff has approved
8 uprates on PWRs up to 17 percent and on BWRs up to
9 20 percent. And so far from the risk assessment and
10 from other reviews we have yet to determine special
11 circumstances.
12 Next slide.
13 One thing that's important in looking at
14 a risk assessment using a PRA is what is the quality
15 or pedigree of the PRA? Beaver Valley has two
16 separate PRAs because the units were sufficiently
17 different. These are full power seismic fire and
18 internal events including internal flooding PRAs.
19 And they calculate the risk matrix, core damage
20 frequency and larger release frequency.
21 For other risks including other external
22 events and shutdown risk, the licensee used
23 qualitative risk assessment.
24 CHAIRMAN DENNING: Unfortunately, George
25 Apostolakis isn't here to say what's a qualitative

1 risk assessment --

2 MR. LAUR: Yes. I noted that. I

3 appreciate that.

4 CHAIRMAN DENNING: That's okay.

5 MR. LAUR: PRA quality, these are

6 uprates of the agency's IPE models, and in the case

7 of the fire and seismic, IPEEE models that were

8 submitted under Generic Letter 88-20.

9 They had an owners review on the

10 internal events portion in accordance with the

11 industry peer review guidelines in 2002 and they've

12 incorporated the resolutions from those comments.

13 The seismic fire PRA models, we don't

14 have an equivalent industry peer review process or

15 standards. However, they were reviewed by the

16 consultants that did the work. I take that back.

17 They were reviewed by consultants when the IPEEEs

18 were performed. And the NRC in the staff evaluation

19 report found them acceptable for meeting the Generic

20 Letter 88-20 purpose.

21 And so the conclusion that I made from

22 all this is that the PRA is of sufficient scope,

23 quality and level of detail to support this

24 application.

25 We also conducted a very focused onsite

1 audit of the licensee's PRA last October. There were
2 several purposes. One was to understand the risk of
3 the EPU taken by itself. A second purpose was to
4 check the quality of the PRA and the risk assessment
5 that was done using the PRA and to understand and
6 clarify some of the RAI responses in an onsite
7 manner as opposed to multiple back and forth on the
8 docket.
9 Let me go to the key findings. The key
10 findings was that the licensee up to that point had
11 not assessed the risk of EPU by itself. There were
12 model enhancements and methodology changes and then
13 modifications to the plant that were unrelated to
14 EPU that were included in the post-EPU model which
15 made the delta risk assessment not apples-to-apples
16 comparison.
17 Also, as a result of the audit we
18 identified the need to explain some apparently
19 anomalous MAAP results.
20 Coming out of the audit the licensee
21 actually identified a MAAP error and reperformed and
22 resubmitted quite a bit of the HRA timing analysis.
23 They also submitted a risk assessment that was more
24 of an apples-to-apples comparison pre-EPU to post-
25 EPU.

1 DR. BANERJEE: Which were the MAAP
2 results that had to be explained? What type of
3 results, do you remember?
4 MR. LAUR: There was a reactor coolant
5 pump seal LOCA calculation for station blackout.
6 Correct me if I'm wrong, I know it was station
7 blackout. I think it was RCP seal LOCA that in most
8 of the cases from pre-EPU to post-EPU timing
9 decreased as you would expect. In one case it
10 actually increased. And so we questioned that. And
11 then on the audit we pulled the thread a little
12 more, the licensee ended up getting Fauske &
13 Associates involved in explaining how the MAAP code
14 works, et cetera. And it turned out the actual
15 timing increase was due to another change, it had to
16 do with the accumulator setpoints. And therefore,
17 it could be explained in terms of the thermal-
18 hydraulics, which was not my expertise, but it could
19 be explained in the fact that more accumulator water
20 went in during the transient.
21 However, in the course of researching
22 that they discovered a modeling error in the MAAP
23 model that required redoing.
24 DR. BANERJEE: Do you recall what the
25 error was?

1 MR. LAUR: They had the pressurizer
2 surge line going into the top of the loop instead of
3 in the middle of the loop.
4 MR. ETZEL: This is Bill Etzel from
5 FENOC.
6 Yes. on the pressurizer surge line the
7 MAAP code we had a loop sealed model where in
8 reality we do not have one.
9 DR. BANERJEE: But why didn't it show up
10 in the pre-EPU calculation and the post-EPU. I
11 mean, the error would have been made in both, right?
12 MR. LAUR: Right. The error was a
13 preexisting error to my understanding.
14 DR. BANERJEE: So why did it give this
15 anomalous result?
16 MR. LAUR: I can't answer that. But I
17 know in my review when we're looking at a table of
18 timing changes due to EPU and you see all of them
19 going in the expected duration, a little bit
20 shorter, and one of them going longer, it causes you
21 to question.
22 But as to why that wasn't caught
23 earlier, I don't know.
24 MEMBER WALLIS: But the two aren't quite
25 so connected. Maybe the result of this lead to a

1 review of MAAP which showed up this error; I'm not
2 sure the two things are connect.
3 MR. KELLER: Yes. This is Colin Keller.
4 That's correct, Dr. Wallis. The two were
5 not related. The error was found in part of the
6 review that we did to the NRC's --
7 MEMBER WALLIS: You were lead to look
8 further at MAAP and then you found something --
9 okay.
10 MR. KELLER: Yes.
11 MR. LAUR: Right. I didn't mean to imply
12 that this error was causing the anomalous result.
13 DR. BANERJEE: So why was there an
14 anomalous result? Then we're back to --
15 MR. LAUR: Well, when I say "anomalous,"
16 it's apparently anomalous --
17 MEMBER WALLIS: But not really?
18 MR. LAUR: -- but the reason for the
19 time getting longer in this one or two scenarios, I
20 don't remember how many there were, had to do with
21 changing accumulator pressure setpoints and level
22 setpoints that resulted a change in addition to or
23 actually opposite to the change caused by power
24 increase. So that in this particular scenario
25 instead of the timing getting shorter, this

1 additional water from the accumulators actually
2 caused it to be longer.
3 DR. BANERJEE: So it was a legitimate--
4 now you accept that as a legitimate finding?
5 MR. LAUR: Yes. Yes.
6 DR. BANERJEE: But at the end of it it
7 allowed you to -- well, not allowed it actually
8 initiated this review of MAAP which found an error.
9 But that error had nothing to do with this?
10 MR. LAUR: That is correct. And the
11 real point I was trying to make here is that they
12 did review the MAAP analyses and resubmit them on
13 the docket.
14 The other result out of the --
15 DR. BANERJEE: Was there any independent
16 check of MAAP or audit of MAAP or was this what was
17 done?
18 MR. LAUR: I don't know. The audit we
19 did was not looking at MAAP. We're looking at very
20 focused on the licensee's configuration control
21 process for MAAP and for risk calculations and on
22 specific areas that we had asked in RAIs that we
23 didn't understand. And this was one of them. But I
24 think there were two MAAP areas, and the one they
25 were able to resolve right away and this one took a

1 little longer.

2 DR. BANERJEE: What was the other area?

3 MR. LAUR: I'd have to look it up. I

4 don't recall offhand.

5 DR. BANERJEE: Okay.

6 MR. LAUR: The other result, though, we

7 did compare the licensee's procedure for

8 configuration the PRA to the ASME PRA standard

9 Section 5 and concluded it was a good process. They

10 had virtually all the elements met for practicing

11 the configuration control by procedure.

12 The licensee already covered the fact

13 that the way we tend to assess the risk is to look

14 at the various elements that make up a PRA and say

15 what could be impacted. And I've got these combined

16 in a couple of slides here. But this one talks

17 about initiating events and equipment reliability.

18 The EPU does not result in any new initiating

19 events. Even in the cases where an initiating event

20 is modeled as a fault tree model of some operating

21 system that fails during its mission time, the

22 equipment reliability is not expected to change

23 either. So therefore, those initiating events would

24 not be impacted.

25 And for the same reason the systems that

1 are mitigating the accidents are not expected to
2 change because they're still operating within their
3 same design limits.
4 Next slide.
5 Accident sequence and success criteria.
6 The general accident progression, accident sequence
7 progression did not change. In other words, the
8 event tree models are the same. Now timing may be
9 different at EPU conditions, but you don't expect to
10 have to ask different questions in the event tree as
11 a result of an 8 percent power uprate. And the
12 licensee concluded that you don't, and I concur.
13 The success criteria for the most part
14 stays the same. And I just want to talk about a
15 couple of places where it didn't.
16 Station blackout is impacted slightly.
17 If you have a station blackout and never recover
18 offsite power, you're going to have core damage
19 somewhat earlier. That translates int the time that
20 the operator has to recover offsite power, which
21 translates into a higher operator action failure
22 probability and therefore core damage frequency.
23 The licensee did include that in their post-EPU
24 model.
25 The ATWS success criteria was impacted.

1 Addition of the cavitating venturies on Unit 1 means
2 you can no longer mitigate a full ATWS event because
3 you can't get full flow out of three AFW pumps.
4 However, the PRA success criteria didn't change.
5 And the reasons for that is that the licensee had
6 conservatively not credited full flow in the pre-EPU
7 model. And therefore, the success criteria is the
8 same. The licensee reported no change in risk.
9 I pointed out in my safety evaluation
10 that that's not correct. There is a change in risk.
11 The change in risk would be if you had taken the
12 conservatism out of the initial, the pre-EPU, and
13 you'd actually get a delta. But I also know to
14 looking at the information they submitted that ATWS
15 is less than 1 percent on both units. Therefore,
16 the max that could be would be a 1 percent. It
17 would not change my conclusions.
18 CHAIRMAN DENNING: That really is
19 interesting, though, in terms of just looking at
20 delta risks where, as you quite properly pointed
21 out, that making the conservative assumptions made
22 it look like there was no change in risk whereas in
23 reality there was a slight increase in risk.
24 MR. LAUR: That's correct.
25 CHAIRMAN DENNING: But I agree, it's a

1 negligible consideration.

2 MR. LAUR: The design bases loss of

3 feedwater transient was picked up by one of the

4 other branches and brought to my attention resulted

5 in a request for additional information on how the

6 PRA success criteria was impacted. It turned out it

7 was not. And the licensee submitted realistic

8 LOFTRAN and realistic MAAP calculations to show that

9 in a realistic analysis that the success criteria

10 pre and post-EPU does not change.

11 CHAIRMAN DENNING: Now, is this the

12 success criterion that relates to two out of three

13 aux feedwater pumps?

14 MR. LAUR: Right. The PRA from a

15 realistic standpoint pre and post-EPU you only need

16 one AFW pump for secondary side decay heat removal.

17 Now in Unit 2 you need two steam generators because

18 you have small atmospheric dump valves but as far as

19 the AFW portion, which is what has been effected by

20 the cavitating venturies, the realistic analysis

21 shows that it does not change.

22 And then the final bullet here is

23 actually the subject of a whole other slide, which

24 is containment accident pressure credit for ECCS

25 NPSH positive suction head.

1 Next slide.

2 This has a potential of impacting

3 success criteria, so that's why I put it under here.

4 I don't know how much you want me to go over this.

5 I thought it was pretty well covered by the Licensee

6 and by Rich Lobel yesterday.

7 CHAIRMAN DENNING: Yes, I think it was.

8 So if you just want to kind of bottom line, feel

9 free.

10 MR. LAUR: The bottom line is if you

11 remember the two graphs that were respective of

12 calculations before and after, there's a difference

13 of about 30 seconds to one minute when they cross

14 zero, in which I concluded there was an incalculable

15 risk impact, delta risk impact, from crediting the

16 containment accident pressure.

17 MEMBER WALLIS: Does all this go into

18 the PRA then? I mean you have an actual evaluation

19 of the change in the PRA as a result of crediting

20 this containment accident pressure?

21 MR. LAUR: No.

22 MEMBER WALLIS: You don't?

23 MR. LAUR: Not to my knowledge. If you

24 look at the absolute value of a contribution to

25 risk, in other words not the change but what it

1 would be, and the licensee indicated that a large
2 LOCA and failure of containment isolation for
3 example would be 1E minus 8. I don't have their
4 model, but what I did look at was a failure on
5 demand. If you use a bounding value for a failure
6 on demand of a containment isolation valve, a
7 typical common cause failure in a bounding LOCA of
8 frequency of ten to the minus four, you're down to
9 ten to the minus seven right there. So you're
10 talking about a very low --
11 MEMBER WALLIS: No, granting there's
12 containment overpressure is not really something
13 that's necessary in order to bring the risk down.
14 It's necessary in order to meet some other
15 requirement.
16 MR. LAUR: That is correct.
17 MR. RUBIN: Dr. Wallis, that's correct.
18 If I could just interject momentarily.
19 This is Mark Rubin, Branch Chief 1.
20 The reason this was looked at is because
21 of the issues related to the VY power uprate and
22 some of the concerns on granting NPSH over pressure
23 and the fact that the Reg. Guide -- I'm sure Mr.
24 Lobel talked about that previously. Because the
25 Reg. Guide is under revision, a senior NRR

1 management asked that we reflect on the potential
2 risk impact to see if any existed on the power
3 uprates and that in the future it be sort of looked
4 at quickly, if all that's required, to validate
5 little to no risk impact. And that's why this was
6 looked at specifically.
7 But the conclusion, you're absolutely
8 correct, has no real impact in this case.
9 MR. LAUR: And the point was already
10 made yesterday, but we're not granting containment
11 overpressure. That's the existing licensing basis.
12 MEMBER WALLIS: There's really no
13 change. It's been granted before and there's almost
14 no change in the requirements, so nothing has really
15 happened here?
16 MR. LAUR: Exactly. That's what we
17 concluded.
18 Human reliability. I guess in keeping
19 with every other EPU that I've heard about, this is
20 the major impact on risk, on calculated risk. EPU
21 has a tendency to reduce times for operators to act.
22 The change in the HRA due to EPU is not assessed
23 directly by the licensee. What was done instead was
24 a sensitivity study. And the reason for that was
25 their pre-EPU timing was, as I mentioned, based on

1 often grossly conservative hand calculations for the
2 time. Their post-EPU they've upgraded to use MAAP
3 on both units.
4 Secondly, the method they used cannot
5 translate small changes in timing into realistic
6 human error probabilities.
7 MEMBER WALLIS: But that's just what
8 they do, isn't it? Isn't that what they do?
9 MR. LAUR: That's what they do. But
10 that's--
11 MEMBER WALLIS: You're saying they can't
12 do it meaningfully?
13 MR. RUBIN: This is Mark Rubin again.
14 Yes, I think that's what we're saying.
15 Some of the HRA methodologies, especially the
16 earlier ones we'll grant, as Dr. Apostolakis has
17 shown us on many occasions. The small change is in
18 timing. The model will calculate a difference in
19 human performance or success rate, but it's really
20 not a meaningful -- you have no confidence really in
21 those small changes shown.
22 MEMBER WALLIS: What else are you going
23 to do? If you're asked to calculate the CDF effect,
24 you have to use some sort of HRA?
25 MR. RUBIN: Yes.

1 MR. LAUR: Yes.

2 MR. RUBIN: Certainly.

3 MEMBER WALLIS: And you're simply saying
4 that this isn't a very good method. I think it's a
5 little extreme to say it's not meaningful. It's
6 maybe the best method available.

7 MR. RUBIN: What is meaningful -- well,
8 certainly it does give a quantitative result. But
9 what is meaningful is that the techniques allow us
10 to identify the more important actions, look at the
11 timing changes for those and see if they're
12 significant and let us focus in risk case.

13 All we wanted to point out here is that
14 we're in the areas of uncertainty, almost in the
15 area of noise in the small calculational
16 differences. But we do use the technology to help us
17 focus in on the important human response actions and
18 look at the timing changes on those.

19 MEMBER WALLIS: I think you ought not to
20 use the word "meaningful" though. That might mean
21 the wrong thing to some people. And you're just
22 saying that there are uncertainties and these are
23 very small changes anyway, and all that sort of
24 thing. But you're still doing the best you can or
25 the licensee is doing the best he can.

1 MR. LAUR: That's a good comment. When
2 I say the "methodology," as I mentioned I used the
3 success likelihood index method, but I'm not
4 integrating that methodology. If you have a time
5 reliability correlation, which I think is an
6 artifact in some ways, but as Mark said you change
7 time, you're going to get a change. And this method
8 has a method on the performance there's a time. If
9 you look at the SPAR-H model, they have discreet
10 time steps ranging from not enough time to adequate
11 time, to excess time. And the point I'll make on
12 the next slide goes to more with symptom based
13 procedures, it's almost a function of can you get to
14 that step in the procedure and then do you have an
15 error of omission when you get to that step.
16 So looking at the third major bullet,
17 the way I assessed the risk was looking at the post-
18 EPU core damage frequency and large early release
19 frequency recognizing that the change in those is
20 based on natural plant changes and on a sensitivity
21 analysis for the HRA. Okay.
22 And I did ask the licensee in an RAI to
23 validate important operator actions with short time
24 frames. You know, demonstrate they can be done. In
25 other words, they are not precluded. I understand

1 you "can" meaning one to zero. What I'm saying is
2 you haven't changed the time to where something that
3 was maybe marginal but you could do it became
4 precluded. And they did that and nothing fell into
5 that category of being precluded.
6 So my conclusions focused on, like I
7 said, that the actual CDF and LERF and whether or
8 not special circumstances arose.
9 Next slide.
10 The licensee showed you a top five
11 operator actions and they gave me whole pages of
12 them, but if you look through them and sort them by
13 importance, I tried to summarize them in two major
14 categories. What shows up are depressurizing the
15 RCS and feed and bleed cooling at both units and
16 then some manual actions to, in the case of Unit 1
17 start auxiliary river water pumps and align them and
18 Unit 2 solid state protection system failure so you
19 have to start aux feedwater pump.
20 The licensee, as I said, validated these
21 and all the other ones that could be performed. But
22 just looking at the feed and bleed actions briefly.
23 These are proceduralized, they're routinely
24 practiced, they're performed in the control room
25 with one minor exception. They take a relatively

1 short time from two to ten minutes to actually
2 perform the tasks. And they occur in response to
3 symptom based procedures, not just the EOPs but also
4 the functional restoration procedures.
5 So the last subbullet under there is
6 what I was trying to say. It's really more of a
7 function of how much time you have until you get to
8 that step in the procedure as opposed to a slight
9 decrease in the amount of time available.
10 And the other two actions up there are
11 control room actions that are simple actions.
12 So we concluded that there was a minimal
13 impact on EPU risk on the HRA.
14 DR. BANERJEE: What about switching to
15 hot leg injection?
16 MR. LAUR: I don't recall that operator
17 action, and I'd have to defer to the utility. That
18 might be a good one for the utility to comment on.
19 MR. ETZEL: This is Bill Etzel from
20 FENOC.
21 We currently do not model hot leg
22 injection.
23 DR. BANERJEE: But you switch, right, to
24 hot leg injection in the log term cooling scenario,
25 right?

1 MR. ETZEL: Yes.

2 MR. DURKOSH: This is Don Durkosh. I'll

3 be addressing that in the next presentation.

4 DR. BANERJEE: Okay.

5 MR. LAUR: Okay. External events, we've

6 got seismic fires and other, which include high

7 winds. There's nothing about EPU that would

8 increase any of the initiating event frequencies or

9 types of initiating events from these.

10 The quantitative assessment, since their

11 PRA handles seismic and fires, demonstrated that a

12 very small impact on the risk from those. And that

13 comes from the fact that their seismic and fire PRA

14 models are integrated with their PRA model. So

15 human reliability increases and plant modification

16 increases translate and propagate through those

17 models.

18 And for other external events, the

19 successive screening methodology that was used for

20 their IPEEE remains valid and we conclude that would

21 be a minimal impact on risk as well.

22 Next slide.

23 I don't have as many as the licensee

24 had, but this shows you the post-EPU core damage

25 frequency and large release frequency using their

1 HRA methodology with a MAAP realistic timing and
2 that is what I used to conclude that there was no
3 special circumstances. These are very small
4 changes.
5 The increases include the modifications
6 and the sensitivity analysis. These small. They
7 meet the Reg. Guide 1.174 guidelines for being
8 small, but it's not what I based my conclusion on
9 for adequate protection.
10 Next slide.
11 The licensee did a qualitative
12 assessment of shutdown risk using the questions in
13 the Standard Review Plan, Chapter 19. And we agree
14 that the shutdown initiating events aren't impacted.
15 Times to boil times for operator actions are
16 slightly decreased, but minimal impact on risk.
17 Finally, in conclusion the licensee
18 assessed the potential risk from EPU. We concluded
19 the EPU does not create special circumstances that
20 would rebut the presumption of adequate protection
21 and therefore we found this acceptable.
22 CHAIRMAN DENNING: Are there any
23 questions?
24 Thank you. Good job.
25 MR. LAUR: Thank you.

1 CHAIRMAN DENNING: Okay. Now we're just
2 going to continue on and we'll get into operations
3 and testing starting off with human factors, I
4 guess.
5 MR. DURKOSH: Okay. My name is Don
6 Durkosh. I am a senior reactor operator currently
7 licensed at Unit 2 and control room supervisor.
8 I also have with me George Storlis.
9 George brings over 30 years of operating experience
10 at Shippingport, Beaver Valley Unit 1 and Beaver
11 Valley Unit 2.
12 A little bit about myself. I have 25
13 years of experience in the commercial nuclear power
14 industry. I started my career with Westinghouse
15 working in the engineering design analysis services
16 area. I was the Westinghouse site manager at Beaver
17 Valley and was in the unique position of kicking off
18 this project and working with Mike Testa from a
19 management perspective.
20 And I am licensed at Unit 2 and looking
21 forward to raising power toward the end of this year
22 at Unit 2.
23 The four areas that I plan to cover are
24 human factors, training, our test plan and overview
25 of our test plan and touch upon large transient

1 testing.

2 From an overview perspective, the human

3 factors impact of the EPU is minimal. There's a

4 total of eight meter changeouts from a control room

5 perspective. Six of them are related to the fact

6 that we're replacing our accumulator pressure

7 indicators with a digital indicator. And we also are

8 replacing our containment narrow range pressure

9 indicators as part of the containment conversion

10 project. All eight of these meters have been

11 replaced out at Unit 1 and on the Unit 1 simulator

12 and in the process of being changed out at Unit 2.

13 Coming into the EPU project we were at

14 an advantage in that in late 2002 and early 2003

15 Beaver Valley Operations staff undertook a major

16 review of our emergency operating procedures. And e

17 have substantially streamlines our EOPs and made

18 them consistent with the Westinghouse ERGs. And, in

19 fact, that's a project that I also worked.

20 So we had a very solid foundation for

21 coming into the final portion of the EPU project

22 having very streamlined procedures.

23 In the big picture here, the procedure

24 changes that are coming out of the EPU project are

25 rather minimally. They're primarily: Revise

1 operating parameters, changes in limits and revise
2 setpoints.
3 One area where the EOPs were directly
4 impacted was the addition of an attachment that will
5 require that the control room initiate a purge
6 following a steam generator tube rupture. However,
7 I do want to point out that that existing attachment
8 already exists for purging the control room for a
9 steamline break scenario. So in a big sense, it's a
10 very minimal impact.
11 DR. BANERJEE: What are those two little
12 things there? What was that interesting stuff.
13 MR. DURKOSH: Go back, but don't click
14 on it.
15 What they are, they are backup slides.
16 What I wanted to do, what I have here are examples
17 of some of the normal operating parameters and some
18 of the EOP setpoint changes. But I looked ahead at
19 the NRC presentation and they have much more than I
20 have, so I don't see any value going there, if
21 that's okay with you.
22 CHAIRMAN DENNING: Thank you.
23 MEMBER WALLIS: What we could do is
24 check that you and the NRC have the same
25 presentation or there's no inconsistency.

1 MR. DURKOSH: All right. Click on it.

2 CHAIRMAN DENNING: Don't click it.

3 Don't click.

4 MEMBER WALLIS: We'll trust you on that

5 one.

6 MR. DURKOSH: All right.

7 Okay. I was at the Ginna presentation

8 so I heard your feedback, what you really wanted to

9 focus on; those areas that were potentially

10 impacted. So, obviously, our action time, operator

11 action time is a key issue so I wanted to address

12 that.

13 Obviously with increased decay heat the

14 available time to perform some actions are reduced.

15 However, I do want to point out that the basic

16 operator actions that we have to do remain

17 unchanged. We are not implementing any new

18 modifications that require new operator action

19 times. And that's unlike Ginna where they did

20 actually implement some modifications.

21 In most cases our action times have

22 either remained the same or actually been extended

23 to improve the overall process. And I do have a

24 couple of slides where the case is actually reduced,

25 and I'll talk about those.

1 During the course of this review we also
2 identify procedure enhancements and we have
3 incorporated those. Most notably, we did a complete
4 review of our fire related procedures for Unit 1 and
5 we did a major upgrade as part of the EPU project.
6 And action times are being revalidated.
7 We've already talked about some using the simulator,
8 using walkdowns, using tabletop discussions and
9 field timing of operator actions in the field.
10 I do want to take a point. Colin had
11 mentioned operator action time relative to the PRA.
12 And for the scenarios that I saw, most of those are
13 beyond design bases. So it gets you pretty deep
14 into the emergency procedures and the contingency
15 procedures. For instance, initiating bleed and
16 feed. There's a loss of heat sink scenario which
17 requires us to lose all of our aux feedwater pumps,
18 not be able to use our main feedwater pumps, our
19 startup feed pumps, our condensate pumps. So we're
20 basically sitting as the steam generators are slowly
21 drying out and getting ready to wait to initiate
22 bleed and feed. So it's a pretty extreme scenario.
23 Okay. The next slide.
24 Okay. We talked about ECCS switchover
25 to hot leg recirc. Ken had talked about and this

1 question just came up.

2 At Unit 1 the existing time is 8 hours

3 and when we go to uprate, that time will get reduced

4 to 6½ hours.

5 At Unit 2 the current time is 7 hours

6 and that will get reduced to 6 hours.

7 And in addition, at Unit 2 our design

8 bases has us switch from straight cold leg recirc to

9 hot leg recirc and back to cold leg recirc on a

10 periodic frequency. That time rate now is 11½ hours

11 and that'll be reduced to 9½ hours.

12 I think the question came up as to what

13 the burden or impact is. Through our simulations

14 generally within an hour or two of a large break

15 LOCA scenario we are back into the emergency

16 mainstream procedure called E1. And basically we

17 are doing our preparations looking down the road and

18 doing our preparations.

19 As was mentioned, approximately one hour

20 before we will start taking steps to make sure we

21 have AC power to the valves in questions. If we

22 have any jumpers that require, we have those jumpers

23 in position. And we're briefing on what actions

24 have to occur.

25 And the time frame for actually

1 initiating switchover, at least I looked at the Unit
2 1 validation efforts on the simulator to initiate
3 hot leg recirc. Coming into the procedure we're
4 talking a matter of minutes. So those hot leg
5 recirc procedures are relatively streamline. You're
6 able to get in and get out very quickly.
7 DR. BANERJEE: I guess the impact would
8 be if one was wrong in determining where the
9 switchover time should be? If it was, say, three
10 hours instead of 6½ h ours, there's no direct
11 measure you have here. But it's not related to the
12 uprate, it's in general this issue of not having a
13 direct measure for the boron?
14 MR. DURKOSH: I agree. It's not
15 directly impacted by the project.
16 DR. BANERJEE: Yes. The amount of time
17 difference is not significant. All right.
18 MR. DURKOSH: Two areas that I would
19 like to talk about is the tube rupture and isolating
20 aux feedwater flow and the post trip fire scenario
21 where if we did lose aux feedwater, we would want to
22 restore it.
23 Relative to the tube rupture, one of the
24 key operator actions is to isolate aux feedwater
25 flow. I do want to point out that all of the EPU

1 analyses that were performed were actually based on
2 crew simulation data collected in 2002. So we had a
3 solid footing for the analyses going forward.
4 And then as part of the EPU project in
5 late last year we ran on the simulator with the new
6 procedures that are being proposed, we had the Unit
7 1 crew go through and then we validated the fact
8 that what we had done before we were able to meet.
9 For Unit 2 this EOP changes are in the
10 final stages of being identified. There were
11 tabletops that were performed and we are planning to
12 do simulator validation later this year.
13 Next slide.
14 Relative to the fire scenarios, key
15 action would be if you lost aux feedwater you'd need
16 to reestablish it. I wanted to give you a positive
17 message here. Relative to the Beaver Valley Unit 1
18 the EPU project established all of the critical
19 operator action times. The entire set of fire
20 related procedures were revised, streamlined and the
21 walkdowns have been completed. So that validation
22 effort is complete.
23 Relative to Unit 2, about 3 years ago
24 our fire related procedures were updated. And it
25 turns out that because that occurred in the midst of

1 this EPU project, the aux feedwater critical times
2 have already been incorporated in the procedures.
3 So there's basically minimal work to do on Unit 2.
4 Possible that any of the lessons learned from the
5 Unit 1 procedures may get back to Unit 2. But we're
6 not anticipating any major changes to our
7 procedures; they're already there. And they've
8 already included the operator action times that are
9 appropriate for EPU.
10 The next slide.
11 Okay. Moving on to operator training.
12 Basically we use classroom training of our design
13 change packages. We'll go over our tech spec and
14 licensing requirement manual changes. We'll go over
15 any physical changes, procedure and setpoint
16 changes. And then also we'll do simulator focus
17 areas where if there is a change warning, a
18 demonstration or hands-on training, we would do
19 that. And for instance, the Unit 1 crews had a
20 chance on the simulator to operate the new steam
21 generator level control program following steam
22 generator replacement. So the crews have time to
23 basically get accustomed to the new control
24 setpoint.
25 And then we always will continue our

1 transient response and EOP execution training.

2 And for startup and shutdown, we also

3 use just-in-time training to get the crews focused

4 in prebrief so that those activities go smoothly.

5 As we discussed over the last day and a

6 half many of the modifications have been

7 incorporated. So crew training has been going on

8 here for the last couple of years as modifications

9 have been made. And they'll continue up to our EPU

10 uprate.

11 We do have plant specific simulators

12 that we use, separate ones for Unit 1 and Unit 2.

13 And the changes that we're talking about are

14 primarily model and initial conditions. So there's

15 no issue about going from current plant to EPU plant

16 other than a matter of a couple of minutes to switch

17 over the model. I know that question was raised at

18 Ginna. So we do not have any issues being able to

19 switch back and forth.

20 Moving on test plan. This is an

21 overview of our test plan. Primarily consists of

22 post modifications tests which, as I mentioned, many

23 of them have already been performed and we'll

24 continue doing them as the mods are made.

25 Our low power physics testing program

1 remains the same. There's no change there. What we
2 are doing is we are collecting baseline data and
3 then using that baseline data to support our power
4 ascension testing. And in the power ascension
5 testing we're planning on small increments. I have a
6 couple of slides to show you of what our current
7 plan is.
8 But basically we'll use the baseline
9 data to make data projections. We'll collect data
10 at steady state conditions and then we'll review
11 that day and if we have any anomalies, we'll
12 evaluate that and identify through our corrective
13 action program what our next step would be.
14 So what I wanted to do here is here's
15 kind of a profile of Unit 1 power ascension profile.
16 As we discussed, we just completed our 1R17
17 refueling outage which involved replacing the steam
18 generators. We have started up and we are operating
19 at a 100 percent power currently. And during the
20 startup process we did collect baseline data at
21 roughly 90 percent and 95 percent. So we now have
22 the data that we can use to predict where we expect
23 to be. Following receipt of the safety evaluation
24 report, we plan to uprate approximately a nominal 3
25 percent power uprate and we'll be using the baseline

1 data to predict where the parameters should be so
2 that we have a method to compare.
3 And we expect to operate the rest of the
4 cycle at approximately 2770 megawatt thermal.
5 And then coming out of the new refueling
6 outage, we expect to return to that power level and
7 make two small moves approximately 2.5 percent each
8 time collecting data, evaluating the data making
9 sure that we're comfortable and then moving up to
10 the ultimate power level of 2900 megawatts.
11 I have a similar slide for Unit 2. We
12 are currently in cycle 12 with a 2R12 refueling
13 outage plan for the fall. Our plans here is to come
14 out of the outage, collect our baseline data at
15 roughly 95 percent. Come up to our current license
16 power of 2689, which is 100 percent power and then
17 initiate shortly thereafter a nominal increase of 3
18 percent up to 2770. And our plan is to operate for
19 the rest of basically the full cycle at 3 percent
20 uprate. And then at the following refueling outage
21 would be the next opportunity to go ahead and
22 incorporate the high pressure upgrade at Unit 2 and
23 basically come out of the outage at the referenced
24 power level and again make two small moves up to the
25 ultimate 2900 megawatt for core license power.

1 DR. BANERJEE: When do you have it all
2 with robust fuel or whatever this new RFA? I don't
3 remember.
4 MR. DURKOSH: I didn't understand the
5 question.
6 DR. BANERJEE: When is the core
7 completely peopled with this robust fuel?
8 MR. DURKOSH: We're there already.
9 DR. BANERJEE: Both units?
10 MR. DURKOSH: That's correct. As part
11 of our extensive planning process for this phased
12 implementation we started five or six years ago when
13 we began to transition to RFA fuel. So both units
14 today as we speak are 100 percent RFA fuel.
15 DR. BANERJEE: Okay. Thanks.
16 MR. DURKOSH: The next topic, I'd like
17 to move on, is the topic of transient testing. So
18 what should be considered when you evaluate the need
19 for transient testing?
20 One thing that is very important is to
21 evaluate the modifications and also to evaluate the
22 NSSS control changes. And then based on that in
23 your test plan ensure that you have adequate
24 coverage for testing.
25 So there was a detailed evaluation that

1 was performed as part of the license amendment and
2 follow up RAIs. As we indicated, each of the
3 modifications will be fully tested. And as I've
4 already mentioned, many of the modifications have
5 already been incorporated and we're gaining
6 operating experience with those modifications.
7 In addition, design engineering did an
8 extensive owners review of the NSSS control
9 supporting analyses. These are the operational
10 transients to make sure that we would not have a
11 reactor trip during selected design bases events.
12 And I think the key point that came out
13 of that is there are no controller functional or
14 logic changes. I know Vermont Yankee had somewhat
15 of a fundamental logic change and transient testing
16 may have been appropriate in that case.
17 We have no new control schemes. And our
18 changes are primarily limited to setpoint changes
19 that have been optimized for EPU conditions.
20 The conclusion from our earlier work is
21 the aggregate impact does not adversely affect plant
22 dynamic response.
23 Next slide.
24 Now Beaver Valley Unit 1 given the
25 replacement steam generators, it was important that

1 we did monitor control systems during startup. And
2 I believe Pete mentioned yesterday that the feedback
3 from the operators was very positive. So our control
4 system operated as expected and in addition we did
5 perform, and this was an area where we thought
6 transient testing was important, we change our valve
7 trims out, we did change our control operating
8 setpoints and we had new steam generators. So there
9 was a transient test performed, and actually it was
10 completed over the last weekend. Basically we
11 imputed a step change and we were monitoring the
12 controller response.
13 If you can go to the backup slide. I had
14 this data provided to me over the weekend. But
15 basically this is the new control point, a nominal
16 65 percent. They imputed a signal that drove the
17 controller down 5 percent and we had minimal
18 overshoot. And then they initiated a similar
19 transient up with minimal overshoot. So overall the
20 control system worked just as planned. We easily met
21 all the acceptance criteria. And this all happened
22 within the last few days over the weekend. So very
23 positive feedback on the test. The test and the
24 control modeling worked just as expected.
25 As mentioned, large transient testing is

1 normally a test that involves reactor trip at some
2 high power. At Beaver Valley any turbine trip
3 greater than 49 percent will result in a reactor
4 trip. As I mentioned, there are no functional
5 changes in the NSSS controls and the supporting
6 reactor trip functions. So we do not believe large
7 transient testing is necessary.
8 In addition, the simulation code, which
9 was LOFTRAN, that we use supported the original
10 plant. LOFTRAN has been around a long time. So my
11 message here is the computer code and the model
12 basically supported the original plant design and
13 basically all Westinghouse plant designs. The
14 startup testing confirmed that the plant matches the
15 model, that computer code and model supports our
16 current operational analyses, we have used it to
17 benchmark our simulators, we use it in our non-LOCA
18 analysis and we use it to optimize the EPU
19 conditions. So no further benchmark testing was
20 deemed necessary.
21 And again, my conclusion is based on the
22 technical changes there's no large transient testing
23 that will be necessary.
24 Slide.
25 So my overall conclusions in the

1 operations and testing area, the key take aways are:
2 Our procedure changes primarily involve
3 operating parameters, limits and setpoint changes;
4 The power ascension process will ensure
5 a controlled, closely monitored, very conservative
6 approach to our new licensed power level;
7 And the modification in the NSSS control
8 changes do not alter the basic design function of
9 those systems, nor introduce a first-of-a-kind type
10 change that will warrant large transient testing.
11 CHAIRMAN DENNING: How is the auxiliary
12 feedwater flow test did following the changes that
13 have occurred with the venturies?
14 MR. DURKOSH: Actually, those venturies
15 were replaced I think in the previous outage. But
16 generally what we do is we have an aux feedwater
17 flow test, an operations surveillance test. And
18 there were predictions on what the flow requirements
19 are. And then we have tested the system.
20 CHAIRMAN DENNING: Yes. And actually
21 test it and add water to the steam generator within
22 those tests?
23 MR. DURKOSH: Yes. We normally will do
24 that in the last stages of plant startup.
25 MR. HANLEY: Yes. This is Norm Hanley

1 from Stone & Webster.

2 And, again, when we implemented the

3 modifications to add the venturies, we did use the

4 OSTs to monitor the flow to the -- we also did a

5 very detailed calibration with the venturie itself

6 with the vendor. We did extensive tests to make

7 sure the calibration and the predicted flows would

8 match. We did an OST test where we did pump water

9 to the generator and verify those conditions. And we

10 also did an OST on the pump to verify the pump curve

11 was matching what we used in the analysis.

12 MEMBER MAYNARD: And you do this test

13 coming out of each outage, don't you?

14 MR. DURKOSH: That is correct.

15 MEMBER MAYNARD: I mean as far as the

16 flow test, the calibration?

17 MR. HANLEY: That's correct.

18 MR. DURKOSH: That's correct.

19 Any additional questions? All right.

20 Thank you very much.

21 CHAIRMAN DENNING: Okay. We will go

22 ahead and continue to hear from the Staff.

23 You may proceed.

24 MS. MARTIN: Good morning. I'm Kamishan

25 Martin. I'm a human factors engineer in branch of

1 Operator Licensing.

2 For our evaluation we reviews

3 procedures, training in human factors, interface --

4 CHAIRMAN DENNING: I think you're going

5 to have to speak louder. And is that mike working

6 for sure.

7 The room's been all changed around and

8 so we're having some trouble with the mikes. And

9 you really have to get right up to this mike, too, I

10 know from experience here.

11 MS. MARTIN: Okay. Can you hear me?

12 CHAIRMAN DENNING: Okay.

13 MS. MARTIN: The areas we reviewed

14 include the training and human factors interfaces

15 between the operator and the control room and in the

16 plant related to performance.

17 These are the regulatory guidelines that

18 I use in the evaluation.

19 The main areas that we use that we

20 evaluated include the EOPs and the AOPs, the

21 operator actions that are sensitive to the power

22 uprate, the control room alarms, the SPDS and the

23 training program and simulator.

24 As the licensee stated, the changes were

25 slight modifications for parameter thresholds and

1 the elimination to references to the BIT tech spec.
2 This was eliminated because it's no longer credited
3 as a source of boron -- borated water. Sorry.
4 There was one new operator action that
5 was introduced due to the EPU and that includes the
6 control room purge. And the one change was a change
7 to another purge of the control room dealing with
8 the steam generator tube rupture. I'm sorry. That's
9 a new action.
10 The time reductions, some of the time
11 reductions for operator actions were due to decay
12 heat, but as the licensee stated, most of them
13 stayed the same. There were only a couple that were
14 reduced due to the EPU.
15 In Unit 1 all of the action times were
16 validated through the simulator and through the
17 walkthrough in the plant.
18 For Unit 2 the in plant operator action
19 times were validated, but because the procedures
20 aren't finalized at this time they only did a
21 tabletop review. But the licensee has committed to
22 validating the times on the simulator once the
23 procedures are finalized. We determined this to be
24 acceptable because of their commitment to validated
25 operator action times on the simulator.

1 This is just a table with the operator
2 action times that were most sensitive to the EPU.
3 In Unit 1, as I stated, all of them were
4 validated. But in Unit 2 there was in particular
5 that didn't have a margin between the time available
6 and the time it would take the operator to actually
7 perform this. But it hasn't been validated at this
8 time because the procedures aren't finalized.
9 CHAIRMAN DENNING: Now let me see if I
10 understand. Whose evaluation of action performance
11 time was this, the 9.7 minutes for example in this
12 first action? That's the plant says it can be done
13 in 9.7 minutes or somehow you guys did it?
14 MS. MARTIN: No, the plant said that it
15 could be done.
16 CHAIRMAN DENNING: Yes.
17 MS. MARTIN: And they performed a
18 validation of this because it's in Unit 1 that it
19 could be finished in 9.7 minutes.
20 MR. DURKOSH: Okay. This is Don Durkosh
21 from Beaver Valley.
22 The Unit 1 operator action times were
23 validated last fall on the simulator.
24 CHAIRMAN DENNING: Now, why don't you
25 stay there just a second. And that is this action

1 performance time versus time available, I mean
2 obviously there's extremely small margin between 9.7
3 minutes and 10 minutes. Is that just a conservative
4 value as to we're 99 percent confident that it can
5 be done within 9.7 minutes or what's the difference
6 between the 9.7 minutes and the 10 minutes there?
7 Can you respond to that?
8 MR. DURKOSH: Sure. As was discussed in
9 the non-LOCAs presentation from yesterday, the 10
10 minutes was the assumed operator action time for
11 basically terminating an inadvertent SI basically
12 precluding additional safety injection flow into the
13 pressurizer. And they made an assumption of 10
14 minutes that operator action could be accomplished.
15 And we confirmed that we were able to do it within
16 10 minutes.
17 MEMBER WALLIS: How much time is
18 available?
19 CHAIRMAN DENNING: Ten minutes. And the
20 10 minutes is the rough criterion that you have of
21 you have to do it within 10 minutes, right?
22 MR. DURKOSH: That is correct. And
23 where it says "Time Available/Times used in the
24 analysis," that's the specified time, that's the
25 target time that we're aiming at reaching.

1 MEMBER WALLIS: I'm assuming the time
2 available is longer than 10 minutes.
3 CHAIRMAN DENNING: Well, let me put a
4 hypothesis down and then you can tell me why I'm
5 wrong. Suppose this action in performance time if
6 that was the mean time that it took staff to do
7 this, then the probability of successfully doing it
8 within this time would be about 50 percent. And I'm
9 sure you're not telling me that. What is that 9.7
10 minutes telling me? That's not the mean time to
11 perform it. What is it?
12 MR. SENA: This is Pete Sena again.
13 Dr. Denning, if I can back up slightly.
14 If you recall during the non-LOCA transients for the
15 inadvertent SI, the way we went through that
16 transient was for the design bases assumptions we
17 bias steam generator or correct in pressurizer level
18 an additional 7 percent high from the norm and you
19 put in these various conservatisms.
20 When we go through the design bases
21 transient, the design folks that 10 minute window to
22 get it done. So the operating crews go through the
23 EOPs E zero, ES1.1 for inadvertent SI and all
24 simulator crews went through the scenario and were
25 able to perform that action within the 10 minute

1 time period.

2 CHAIRMAN DENNING: So are you saying the

3 conservatism is within the 10 minutes?

4 MR. SENA: Yes. That's correct. But

5 again when we went through the analysis the way we

6 qualified the acceptability of the analysis was

7 through the qualifications of the downstream piping

8 and the PORVs and not relying on the operator action

9 time. That's how we precluded the event from going

10 from a condition II event to a condition III event.

11 MEMBER WALLIS: Well, what does the 9.7

12 minutes mean?

13 MR. SENA: Well, that is the actual time

14 that the operating crews completed the performance

15 in.

16 CHAIRMAN DENNING: All of them or --

17 MEMBER SIEBER: The slowest one or the

18 average?

19 CHAIRMAN DENNING: -- the slowest one?

20 Yes.

21 MR. SENA: I cannot recall. I believe

22 that might have been the maximum time, but let me

23 get back to you. Let me phone call.

24 MEMBER WALLIS: The average, it isn't

25 very good.

1 CHAIRMAN DENNING: Right. Other than the
2 fact there's conservatism in 10 minutes, but then we
3 don't have a real good feeling as to how much
4 conservatisms.
5 MR. CARUSO: And let's ask once again if
6 the operators don't get it done until 11 minutes,
7 what does that mean?
8 MR. FREDERICK: This is Ken Frederick.
9 In a realistic sense it probably means
10 that they will be closer to overfill. In the safety
11 analysis world that means that we'll cycle the
12 safety valve a couple of more times.
13 MR. DURKOSH: So Ken gave you the
14 analysis impact. From a simulator perspective and
15 all the training that we have received, I cannot
16 recall ever challenging an overfill condition on
17 this kind of transient. We have streamlined our
18 procedures. We can get to SI termination very
19 quickly within 10 minutes. And normally when we
20 would stop the simulator at that point, we're
21 nowhere close to being overwhelmed.
22 MEMBER MAYNARD: I think the importance
23 of this is whether it ends up being classified as a
24 condition II or condition III event. In reality if
25 they don't get it done at all, you're still covered

1 but your safety analysis just goes into a different
2 wonder. But it's whether this is considered a
3 condition II or condition III event.
4 CHAIRMAN DENNING: In this particular
5 case.
6 MEMBER MAYNARD: Right.
7 MEMBER WALLIS: Does this chart come
8 from a FENOC submittal? Is this something that you
9 put together.
10 MS. MARTIN: I'm sorry, what was the
11 question?
12 MEMBER WALLIS: Is this chart taken from
13 the FENOC submittal or is it taken from--
14 MS. MARTIN: I put this chart together
15 from information that was in a chart that they
16 submitted that had more --
17 MEMBER WALLIS: I was wondering why we
18 hadn't seen something like this before.
19 MEMBER MAYNARD: I thought this was
20 discussed a little bit yesterday.
21 MEMBER WALLIS: Yes, I think it was.
22 But we seem to be seeing it a different way now than
23 we did yesterday.
24 CHAIRMAN DENNING: Yes.
25 MEMBER WALLIS: Now it doesn't look so

1 good.

2 MEMBER MAYNARD: Well, again, I think we

3 had a similar discussion yesterday, though, in that

4 what happens if the operator doesn't get the action

5 done.

6 MEMBER WALLIS: Yes.

7 MEMBER MAYNARD: And you're still

8 covered with your small break LOCA or whatever other

9 analysis is covered. It's whether or not this ends

10 up being a condition II or condition III event. And

11 that's what was discussed with one of the NRC

12 presenters --

13 CHAIRMAN DENNING: Well, that certainly

14 is true in that first one. I'm not sure that that's

15 true for everyone of these.

16 MR. DURKOSH: Well, I can address the

17 other ones if you'd like.

18 CHAIRMAN DENNING: Well, why don't you

19 go ahead and do that?

20 MR. DURKOSH: Okay. Sure.

21 So in the case of Unit 2, as I

22 mentioned, an isolating aux feedwater on a tube

23 rupture is a key operator action. Previously the

24 previous analyses used 9.1 minutes. Based on the

25 extensive simulator crew evaluations from, I think

1 2002, they came up with 5.5 minutes as being a very
2 representative time to perform that action. And that
3 was prior to our streamlining of our EOPs.
4 And the action performance time was
5 tabletopped at 5 minute.
6 I do have some data available to me from
7 Unit 1 which I believe it was of the order of less
8 than 5 minutes for Unit 1 on the actual simulator.
9 MEMBER WALLIS: So the now column here
10 is the time used before, pre EPU, is it?
11 MR. DURKOSH: That's correct. It's in
12 the current.
13 MEMBER WALLIS: Okay. So the word "EPU"
14 should disappear from the title.
15 CHAIRMAN DENNING: Yes. And "isolate"
16 is that just an implication as far as offsite doses
17 from the steam generator tube rupture or does it
18 have more dire implications?
19 MR. FREDERICK: This is Ken Frederick.
20 Yes. Each individual action in the tube
21 rupture procedure and the analysis associated with
22 that is trying to minimize overfill of the
23 generator. So for these particular cases --
24 CHAIRMAN DENNING: Overfill.
25 MR. FREDERICK: -- the goal is not to

1 fill up the steam generator.

2 CHAIRMAN DENNING: Okay.

3 MEMBER MAYNARD: Okay. Some of this

4 also is to keep you from wasting water to the

5 ruptured steam generator there?

6 MR. FREDERICK: Right.

7 MR. CARUSO: And what are the

8 consequences of overfilling the generator?

9 MR. FREDERICK: If you overfill the

10 generator, then you lose iodine partitioning, which

11 makes the offsite doses go up.

12 CHAIRMAN DENNING: Okay. I think we're

13 content with this figure.

14 MEMBER WALLIS: I suppose we are. And

15 just a little bit mystified.

16 CHAIRMAN DENNING: Yes.

17 MEMBER WALLIS: If we're just comparing

18 columns and you say you need 2 minutes and you got 2

19 minutes, that doesn't really help me much.

20 CHAIRMAN DENNING: Now, I don't think

21 any of these are identified as important human

22 actions from a risk assessment. Is that a true

23 statement? Do we still have risk people here? Are

24 they --

25 MEMBER WALLIS: I think we do.

1 MR. LAUR: This is Steve Laur again, NRR
2 Division of Risk Assessment.
3 I don't know what the relationship
4 between the design bases accident and the PRA is.
5 But certainly cool down -- the action to cool down
6 is one of the risk important operator actions.
7 I would point out that this a design
8 bases discussion looking at the inputs from Chapter
9 15 and not a risk assessment.
10 CHAIRMAN DENNING: Yes.
11 MR. LAUR: And as I understand it, what
12 the human factors are doing is verifying or
13 validating that basically a go/no go criteria that
14 you can meet the time whereas in the PRA risk
15 assessment they use realistic timing and realistic
16 scenarios and calculated the frequency of core
17 damage sequences. So really it's not a comparable
18 set of information.
19 CHAIRMAN DENNING: Yes. It does,
20 however, give us a feeling as to what significance
21 of margin in the design bases. But I think you're
22 absolutely right, that that's probably the context
23 that we ought to be interpreting this in rather than
24 risk.
25 And I'm ready to move on to the next

1 viewgraph.

2 MS. MARTIN: These are the times that

3 the licensee provided, the data that will be changed

4 due to the EPU setpoints. This is a representation

5 of the data that will change.

6 In the control room there will be no new

7 displays except for as the licensee mentioned

8 earlier, the SI accumulator should be upgraded to a

9 digital display.

10 And all of the setpoints and displays

11 will be normalized so that 100 percent remains a 100

12 percent and the actions don't change due to the

13 renormalization.

14 For the SPDS, these are just the

15 representation of the changes that will come.

16 Nothing major. And this describes the change

17 process that will be implementing the changes that

18 we'll have.

19 For the simulator, as they mentioned

20 previously, both the simulators have been

21 benchmarked with engineering models. And they will

22 be using the systematic approach training to train

23 the operators for the --

24 CHAIRMAN DENNING: Thank you.

25 MS. MARTIN: This is just more general

1 information on the simulator changes and how they
2 will cover the training for the simulator changes.
3 Our conclusion is that the licensee
4 addressed the effects of the EPU on human factors
5 and they have taken the appropriate actions to
6 assure that the EPU does not adversely affect the
7 operator actions. And we find these proposed
8 changes to be acceptable because of their commitment
9 to validation on Unit 2 and because of the issues
10 that they've addressed.
11 CHAIRMAN DENNING: Very good. And I
12 think we see no other questions.
13 Thank you very much.
14 And we'll move on to what is the last
15 technical presentation, I think.
16 MR. PETTIS: Good morning. My name is
17 Bob Pettis. I'm with the Division of Engineering.
18 I'm filling in for Greg Galletti who was the
19 technical reviewer for the Beaver Valley EPU. At
20 present he's currently at Vermont Yankee and the
21 license renewal inspection. So I'll do the best I
22 can with what was the basis of his review.
23 As you're aware, the power ascension and
24 testing program is covered under the SRP 14.2.1 and
25 which we've had many discussions over the last

1 several months.

2 The EPU test program should include

3 sufficient testing to demonstrate that the SSCs will

4 perform satisfactorily at the request power level.

5 The Staff guidance considers the original power

6 ascension test program that was done under the Reg.

7 Guide 1.68 process and the EPU related plant

8 modification, which most of the modifications fall

9 into the area of plant systems branch which they

10 probably have already provided their evaluation to

11 you folks earlier today.

12 Staff guidance acknowledges that

13 licensees may proposal alternative approaches to

14 testing without adequate justification. We've

15 centered around the large transient testing issue,

16 but it's basically any departure from the original

17 test program is reviewed as part of the technical

18 justification for allowing those exceptions.

19 The Staff basis for requiring

20 performance of testing including the large transient

21 testing fell into the Reg. Guide 1.68 document

22 which was basically established to ensure that there

23 was a suitable test program at the original plant

24 licensing phase that covered both the steady state

25 and anticipated transients.

1 The objectives of Reg. Guide 1.68 were
2 to familiarize operators with training, confirmation
3 of design and installation of equipment, benchmark
4 of analyses and codes and also to confirm the
5 adequacy of EOPs.
6 One of the main objectives with 1.68 was
7 also to provide necessary assurance that the
8 facility could ge operated in accordance with the
9 design requirements and validate any analytical
10 models.
11 Under the Reg. Guide 168 there were a
12 series of tests that were recommended back in the
13 appendix. And two of those tests that were in the
14 original 1.68 guidance were the so called large
15 transient tests which are under discussion for the
16 new plants today. And both of those tests that were
17 required at original plant construction, again to
18 validate analytical models in performance of a brand
19 new plant.
20 Beaver Valley is planning on performing
21 additional startup tests which were originally not
22 part of the initial startup test program to maintain
23 consistency with that of Unit 2. And I believe from
24 what I could look at the SE, it had to do with the
25 fact of the vintages of Unit 1 versus Unit 2 in

1 order to have both plants be somewhat the same, the
2 additional tests were included to make that happen.
3 Some of those examples included the
4 secondary system vibration frequency and amplitude
5 test, system expansion and restraint test, turbine
6 plant system tests.
7 Beaver Valley will perform a series of
8 post mod tests for plant design changes associated
9 with the power uprate. A few of those are listed
10 here. Replacement of main instrumentation,
11 modification of HB turbine.
12 With respect to the transient testing
13 issue, Beaver Valley like most others that have come
14 before the agency, have elected not to perform the
15 two large transient tests which are the MSIV closure
16 and the generator load reject. Some of the accepted
17 justification for not performing these tests for
18 some of the previous plants were that the licensee's
19 test program will monitor the important parameters
20 during the power ascension test phase. And most of
21 that occurs within 2½ to 5 percent increments where
22 the licensee monitors the power ascension.
23 Tech surveillance and post mods will
24 confirm the performance and capability of the
25 modified components through tech spec testing,

1 through normal QA and Appendix B type testing.

2 Operating history is a big factor that

3 quite a few applications take credit for, which is

4 listed in the SRP. And they've cited North Anna,

5 Summer and Harris as similar plants that have

6 undergone the uprates.

7 CHAIRMAN DENNING: Normally we tend to

8 challenge the Staff in this particular area. But in

9 all honesty, I don't think that there's any real

10 serious concerns about large transient testing in

11 this particular uprate.

12 MR. PETTIS: Okay.

13 MEMBER SIEBER: Percentage of power

14 increase is really pretty small.

15 MR. PETTIS: I believe this 108 percent

16 on Beaver Valley.

17 MEMBER SIEBER: Yes.

18 MR. PETTIS: But just to maybe reenforce

19 that--

20 CHAIRMAN DENNING: And also looking at

21 the lack of major modifications in --

22 MR. PETTIS: Yes. I was just going to

23 mention that the technical staff in the balance-of-

24 plant section identified that the balance-of-plant

25 modifications don't warrant the need for the

1 transient testing.

2 So based upon that part of the Staff's

3 review, the Staff concludes that the EPU is

4 satisfactory.

5 CHAIRMAN DENNING: Are there any

6 questions? Thank you very much.

7 MR. PETTIS: Okay. Thank you.

8 CHAIRMAN DENNING: Well you never

9 thought you were going to get away that easy, did

10 you?

11 MR. PETTIS: No.

12 CHAIRMAN DENNING: Okay. Well, I don't

13 hear anybody saying we ought to go to lunch. Let's

14 finish out.

15 MEMBER SIEBER: If you want me to.

16 CHAIRMAN DENNING: Yes. Okay. So,

17 first we'll hear from FENOC management and their

18 wrapup.

19 MR. LASH: Again, I'm Jim Lash, Site

20 Vice President. And I will be brief. I know I'm us

21 and lunch.

22 The past two days I think our team as

23 well as the NRC the presentations have concluded

24 that the reviews have been detailed and there have

25 been no safety issues identified and the Beaver

1 Valley approach is a conservative approach both from
2 an analysis as well as a power escalation that we
3 plan to employ at the station. And I assure you that
4 the implementation of the power uprate will be
5 performed safety and reliability using our plant
6 modification process, our operator training program,
7 our plant procedure modification processes and our
8 adherence to the operating conditions.
9 That completes our presentation unless
10 there are questions from myself.
11 CHAIRMAN DENNING: I don't see any
12 questions. I would like to thank you and your staff
13 for a very good presentation.
14 And as far as the full Committee
15 meeting, we'll give you some more guidance as to
16 what our expectations there. We have two hours
17 there.
18 There was a little bit of duplication
19 between some of the regulatory Staff's presentations
20 and some of your presentation. I think that our
21 guidance will be largely that we're going to focus
22 more on your presentations in a few areas, and some
23 of them are obvious.
24 MR. LASH: Sure.
25 CHAIRMAN DENNING: We're going to want

1 to certainly focus on the results of the accident
2 analyses. But some other areas that aren't
3 necessarily problems, but which ones has to look at
4 like potential for vibrations and stuff like that.
5 I think your story today was quite good on that.
6 We'll have to abbreviate those.
7 And we'll give you some more guidance as
8 to what the presentations.
9 MR. LASH: I appreciate that. I was going
10 to ask you for that guidance. And I appreciate
11 that.
12 CHAIRMAN DENNING: Yes. I think that
13 rather than attempting to really lay it out at this
14 meeting, Ralph will send you a message that kind of
15 indicates how much time to figure on.
16 MR. LASH: Okay. Good.
17 CHAIRMAN DENNING: And in which areas.
18 MR. LASH: Very good.
19 CHAIRMAN DENNING: But there's nothing
20 missing that I see, you know, that we're going to
21 have to have additional things. It's really a matter
22 of compressing and perhaps eliminating in some
23 areas. And from the Staff's side, I think it's going
24 to be an elimination in a lot of areas of some of
25 the reviews that were of value to us to make sure

1 that we saw that they had been comprehensive in
2 their reviews and to see what their considerations
3 were, but as far as the full Committee is concerned
4 I think would be unnecessarily duplicative.
5 MR. LASH: Okay. Thank you.
6 CHAIRMAN DENNING: Okay?
7 MR. LASH: I do have another question,
8 though.
9 CHAIRMAN DENNING: Yes.
10 MR. LASH: And that is just to confirm I
11 think we've been checking all along. I don't believe
12 we owe the Subcommittee anything?
13 CHAIRMAN DENNING: Let me just see if
14 Ralph agrees.
15 MR. CARUSO: That's correct.
16 CHAIRMAN DENNING: Although it looked at
17 some points like there might be, everything has been
18 provided that we had asked for.
19 MR. LASH: Okay.
20 MEMBER SIEBER: Well, if Ralph has some
21 of this typical --
22 MR. CARUSO: I'll be getting a copy of
23 the WRP-2M. I'll send you off that today or
24 tomorrow.
25 MR. LASH: Okay. Good.

1 CHAIRMAN DENNING: Okay?

2 DR. BANERJEE: And ATWS, I guess, but

3 you have that.

4 MR. CARUSO: And I'll give you a copy of

5 BACCHUS, too.

6 CHAIRMAN DENNING: Yes. Yes.

7 MR. LASH: Very good. I would like to

8 thank the Subcommittee for allowing us to make this

9 presentation of our power uprate proposal.

10 I'd also in your presence like to thank

11 my team, which includes the subcontractors from

12 Westinghouse and Stone & Webster for supporting us.

13 The folks worked very hard. Their preparations were

14 very thorough and I think that bore itself out in

15 their presentations. So I thank the team as well.

16 That's it.

17 CHAIRMAN DENNING: Thank you.

18 MR. LASH: Thank you.

19 CHAIRMAN DENNING: And wrapping up for

20 the Staff?

21 MR. COLBURN: I don't have any slides,

22 so I can do that from here.

23 My name is Tim Colburn again.

24 And I'd just like to thank the

25 Subcommittee also for allowing the Staff to make its

1 presentation.

2 We reviewed the licensee's submittal

3 against all of the areas in the Review Standard RS-

4 001. We had a challenging review. There were

5 numerous requests for additional information we

6 provided to the licensee, but they stepped up and

7 provided information every time we asked them

8 questions that resolved all of our issues.

9 The Staff believes that the licensee has

10 done a very good job in resolving the open items

11 that we have along the review path and also in

12 ultimately demonstrating that they can adequately

13 and safely implement the power uprate of 8 percent

14 for Beaver Valley Units 1 and 2.

15 And, again, look forward to whatever

16 guidance the Committee would like to provide us on

17 preparing for the full Committee.

18 CHAIRMAN DENNING: Very good. Thank

19 you.

20 Any questions or comments from the

21 Subcommittee?

22 Anything else we want to discuss before

23 we --

24 MEMBER WALLIS: Well I think we should

25 establish that we don't have any sort of outstanding

1 questions or anything.

2 CHAIRMAN DENNING: Absolutely. Jack, do

3 you want to start off?

4 MEMBER SIEBER: I would indicate that I

5 worked at Beaver Valley for many years. So I don't

6 have a bias one way or another.

7 When I read the application and through

8 the SER, I found the application pretty easy to

9 read, it was straightforward, easy to follow,

10 legible, made sense. On the other hand, that was

11 your second shot at it, I think.

12 In the SER it indicates a lot of

13 requests for additional information that tell me

14 that maybe the first application wasn't real

15 complete.

16 On the other hand, all of that has been

17 remedied and I think the document is in good shape.

18 And I think the modifications that you intend to

19 make on the plant are reasonable. The EPU level

20 that you chose is reasonable because you still

21 remain sort of in the middle of the pack as far

22 experience is concerned. There are a number of

23 plants like yours that operate basically with the

24 same parameters. So you're not blazing ground in

25 that area.

1 I was impressed with the presentations.
2 I think that they demonstrated a good knowledge of
3 analytical methods that were used and what they
4 meant. And I congratulate your staff for that.
5 We had a discussion with some of your
6 folks at the Ginna EPU and I noted that you've been
7 sending people out to see what goes on in these
8 meetings as a way to prepare for this meeting. And,
9 obviously, you learned a lot because this meeting in
10 my opinion went very well. The questions that we
11 asked and that were important were answered well and
12 with the analytical backup and operating experience
13 backup. And I think those factors are important.
14 As far as issues are concerned, I don't
15 see any issues that arise from this application.
16 And I agree with the Staff's conclusions. And when
17 we get an opportunity to vote on Rich's letter which
18 he'll write, hopefully --
19 CHAIRMAN DENNING: I'd better. They
20 don't pay me otherwise.
21 MEMBER SIEBER: -- I personally feel in
22 the affirmative at this time with regard to granting
23 the uprate.
24 So that would be my conclusion.
25 CHAIRMAN DENNING: Thank you.

1 Sanjoy, do you want to comment?

2 DR. BANERJEE: I think that the approach

3 taken is quite conservative and lies within the

4 bound of what has been done before. So I have no

5 particular concerns.

6 I think I'd like to follow up a little

7 bit more on the fate of the boron, which I will do

8 when I look at the BACCHUS report. And a little bit

9 more on the refluxing mod. But other than that, I

10 have no major points. But the applicant doesn't

11 really have to supply any more information at this

12 time.

13 CHAIRMAN DENNING: Let me interject that

14 with regards to the boron, I think there is more

15 work that has to be done here. But not within the

16 context of this EPU. And I have some

17 recommendations that I will to the Staff about how I

18 think that ought to be done there.

19 DR. BANERJEE: Far more generic issues

20 which --

21 CHAIRMAN DENNING: Yes.

22 DR. BANERJEE: -- should not necessarily

23 be a burden on the applicant.

24 CHAIRMAN DENNING: Yes.

25 MEMBER SIEBER: Yes, I agree with that.

1 CHAIRMAN DENNING: Graham?

2 MEMBER WALLIS: Well, I'm glad Jack made

3 the speech, now I don't have to make it. I'm pretty

4 satisfied with what I've heard.

5 I think in front of the full Committee

6 you just have to present the key things and what are

7 the main effects of the EPU as they effect the

8 criteria for reactor safety; how do you meet those

9 criteria. That's really the main issue.

10 Try to avoid a long discussion on PRA

11 because, you know, the changes are so very small

12 they don't effect the ultimate decision.

13 CHAIRMAN DENNING: Okay.

14 MEMBER WALLIS: I think there are some

15 of these questions like the boron thing that we keep

16 coming up with need to be resolved better at some

17 time. But that's not something we should hang on

18 this particular licensee.

19 Thank you.

20 CHAIRMAN DENNING: Tom?

21 MEMBER KRESS: I think it's all been

22 said.

23 CHAIRMAN DENNING: Otto?

24 MEMBER MAYNARD: I think it's all been

25 said, too.

1 CHAIRMAN DENNING: I think it's all been
2 said, too.
3 We're adjourned.
4 (Whereupon, at 12:01 p.m. the meeting
5 was adjourned.)
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CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: POWER UPRATES (BEAVER VALLEY)

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

LINDSEY BARNES
Official Reporter
Neal R. Gross & Co., Inc.

ACRS Subcommittee on Power Uprates

NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2

April 25-26, 2006

Introduction

Timothy G. Colburn
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Topics for April 25

- **Background for Application (Staff)**
- **Introduction and Overview of the Application (Licensee)**
- **Plant Changes (Licensee)**
- **Fuel and Core Design (Licensee)**
- **Safety Analyses (Licensee)**
  - Methodology
  - Non-LOCA Events
  - LBLOCA
- **Safety Analyses-Non-LOCA&LBLOCA (Staff)**

Topics for April 25

- **Safety Analyses (Licensee)**
  - SBLOCA
  - Long Term Cooling/Boron Precipitation
  - Containment Overpressure Credit
  - Dose Analysis
- **Safety Analyses (Staff)**
  - SBLOCA
  - Long Term Cooling/Boron Precipitation
- **Containment Analyses (Staff)**
- **Dose Analysis and AST (Staff)**

Topics for April 25

- Materials & RV Integrity (Licensee)
- RV and Boundary Materials (Staff)

Topics for April 26

- **Mechanical Plant (BOP) (Licensee)**
  - Cooling Sustems
  - Vibration Monitoring
- **Flow Accelerated Corrosion (Licensee)**
- **Mechanical Systems (Staff)**
  - Vibration, Corrosion/Erosion
  - Pumps and Valves
  - BOP
- **Risk Evaluation (Licensee)**

Topics for April 26

- **Risk Evaluation (Staff)**
- **Operations and Testing (Licensee)**
  - **Human Factors**
  - Training
  - Test Plan
- **Human Factor Review (Staff)**
- **Power Ascension (Staff)**
- **Conclusions (Licensee and Staff)**

Introduction

- Pre-application Submittals
  - Steam Generator (SG) Allowable Value Setpoints
  - Containment Conversion
  - BELOCA
  - SG Replacement (BVPS-1 only)
  - Relaxed Axial Offset Control
- Application with supplements
  - October 4, 2004 application with numerous supplements
  - Licensing Report
- Schedule and implementation

Beaver Valley Units 1 and 2
Extended Power Uprating

Non-LOCA Analysis

Samuel Miranda

NRC Staff Reviewer
PWR Systems Branch

Fuel/Nuclear/TH

- No Change to the Fuel Design
  - Both BVPS Units currently using RFA/RFA-2 with ZIRLO cladding
  - RFA/RFA-2 consistent with other applications
- No Change to the Nuclear Design
  - No Change to the Codes and Methodologies
- Thermal Hydraulics
  - NO DNBR transition penalty
  - VIPRE-01 replaces THINC IV
  - RTDP & STDP

Beaver Valley Units 1 and 2
Non-LOCA Analyses

1. Acceptance Criteria

2. Margins

3. Interpretations of Results - 3 examples:

   Steam System Piping Failures
   Spurious Actuation of ECCS
   Spurious Opening of a Pressurizer Relief Valve

Acceptance Criteria

ANSI-N18.2-1973	Standard Criteria	Analysis Criteria
Condition II anticipated transients, or anticipated operational occurrences (AOOs) [freq > 0.1/yr]	Event is mitigated by no more than a reactor trip; and plant can return to operation after corrective action	
	Event cannot develop into a more serious event	☐ Pressurizer does not fill ☐ Qualify PORVs and/or PSRVs for water relief
	Event does not breach any fission product barrier	☐ CHF is not exceeded ☐ RCPB P ≤ 110% of design P ☐ MSS P ≤ 110% of design P

ANSI-N18.2-1973	Standard Criteria	Analysis Criteria
<u>Condition III</u> infrequent incidents [0.01/yr ≤ freq ≤ 0.1/yr]	Small fraction of fuel rods may fail. 10 CFR 20 ≤ releases ≤ public restrictions outside Exclusion Area Boundary	☐ Meet Condition II criteria ☐ Show that only a small fraction of fuel rods fail; which meets release criterion
<u>Condition IV</u> limiting faults [freq < 0.01/yr]	Releases < 10 CFR 100 guidelines	☐ Meet Condition II criteria ☐ Fuel rod failures & dose
	Event does not cause loss of functions needed to cope with the fault (e.g., RCS and containment)	☐ 10 CFR 50.46 ☐ No hot leg saturation (a Westinghouse criterion)
ATWS	Not applicable (see WASH-1270) 10 CFR 50.62 requires DSS and AMSAC	Best estimate analyses show: RCS P ≤ ASME Level C stress limit (3200 psig)

Margins

Margin in the Safety Analysis Limits (SALs)

- CHF

DNBR ≡CHF/HF

Example (WRB-2M):

DNBR Correlation Limit 95/95 value, including empirical uncertainties	1.14
DNBR Design Limit (DL) Correlation limit + operational uncertainties	1.22
DNBR SAL DL + DNBR margin	1.55
DNBR Margin (1- DL/SAL), %	21.2

- RCPB

RCS Level C stress limit (psia) Best Estimate (e.g., ATWS)	3215
RCS P SAL (psia) Conservative (110% design P)	2749
RCS P margin (%)	17

Margin in the Safety Analyses

- Acceptance Criteria

  - Some events are judged according to more stringent acceptance criteria (e.g. steam line break)

  - There is margin between some analysis acceptance criteria and the standard acceptance criteria (e.g., hot leg saturation; pressurizer no-fill; fraction of failed fuel rods)

- Initial Conditions and Parameter Values

  - For each event analysis, uncertainties are applied to initial conditions in the conservative direction, for that event (e.g., power, RCS temperatures, SG tube plugging, pressurizer and SG water levels, protection system setpoints, and core reactivity feedback).

  - Margin is added to key parameter values (e.g., rod drop time, safety injection flow, decay heat generation, and scram worth)

  - Margin is added to system response times (e.g., signal processing delays, pump startup and valve opening times, and isolation valve stroke times

  - Wider-than-expected range of core-related parameter values (e.g., MTC and Doppler feedback) is assumed, to minimize the need to re-analyze events affected by core reloads

- Analysis Methods

  - Conservative critical flow calculations
  - No water entrainment for steam line break, to produce a high cooldown rate
  - Derivative method to underestimate DNBR, based on core limit curves (used by LOFTRAN and RETRAN)

- Transient Assumptions

  - Worst single active failure in the protection system
  - Scram worth based on the most reactive rod stuck outside the core
  - No credit for operation of control grade systems (e.g., pressurizer PORVs, heaters, or spray) unless they would aggravate the transient
  - No credit for some trips (e.g., reactor trip on turbine trip), nor for rods falling into the core when offsite power is lost

Conclusion

There is margin in the safety analysis limits (SALs), and in the safety analysis results.

Application example: CHF criterion

- Min calculated DNBR > DNBR SAL
  Analysis is acceptable since the SAL is met

- Min calculated DNBR = DNBR SAL
  Analysis is acceptable due to the margin inherent in both the analysis and the SAL

- Min calculated DNBR < DNBR SAL
  Analysis is not acceptable since it is not demonstrated that adequate margin exists between analysis result and SAL

Interpretation of Results - 3 examples:

Loss of External Load

A Condition II event that challenges RCPB pressure limit

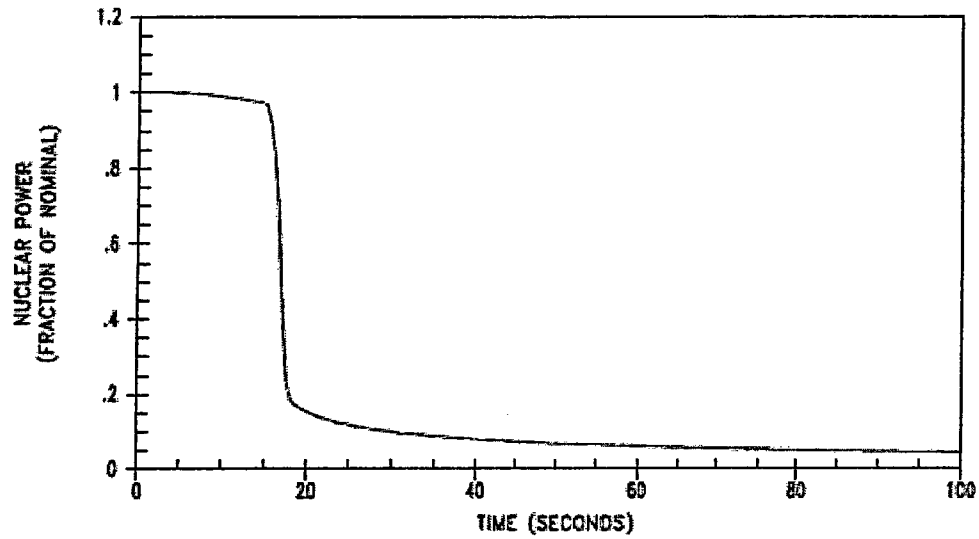
Rod Withdrawal at Power

A Condition II event that tests the ability of the RPS to prevent DNB

Spurious Actuation of ECCS

A Condition II event that could develop into a Condition III event (SBLOCA)

Table 5.3.6-1A BVPS-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip		
Case	**Event**	**Time (Sec)**
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature ΔT Reactor Trip Setpoint reached	12.3
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	8.2



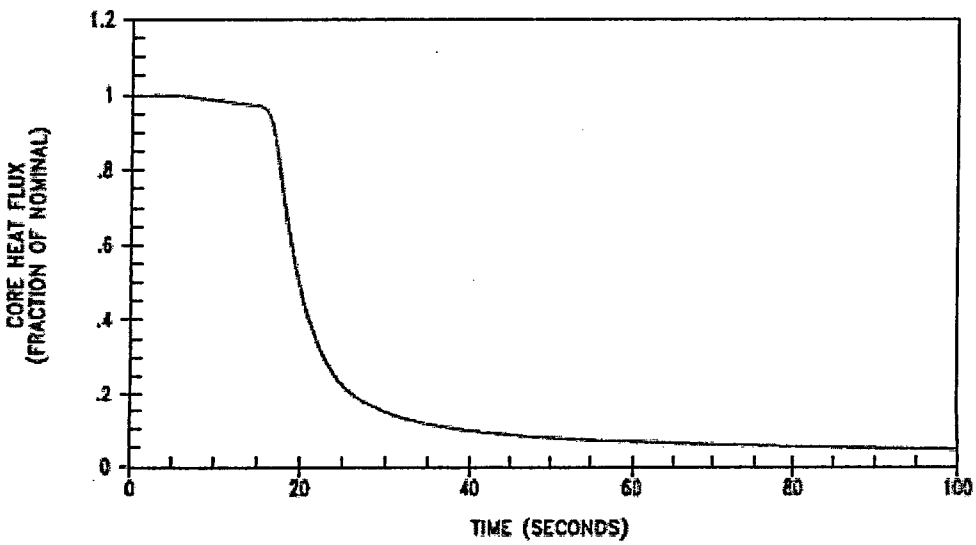
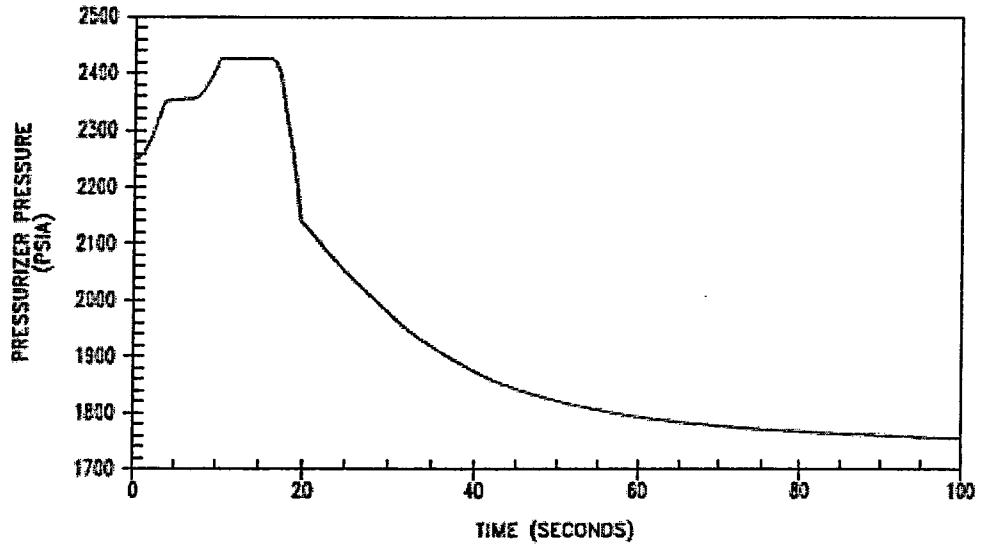


Figure 5.3.6-1A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Nuclear Power and Core Heat Flux versus Time



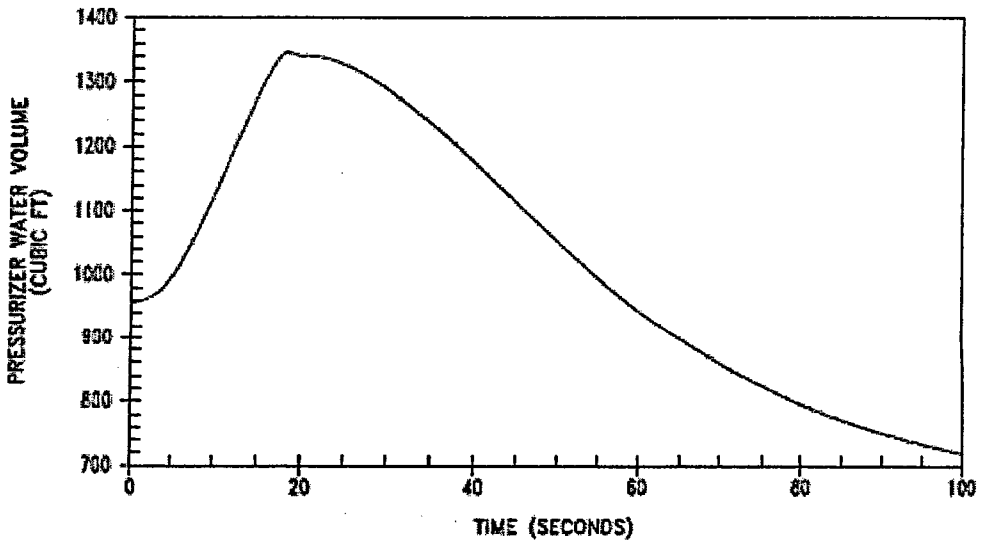
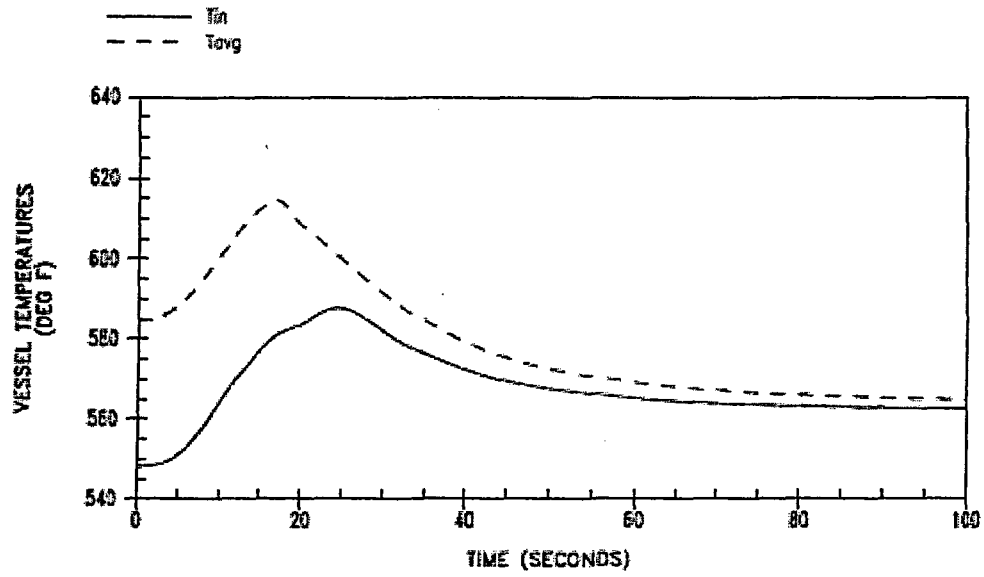


Figure 5.3.6-2A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Pressurizer Pressure and Water Volume versus Time



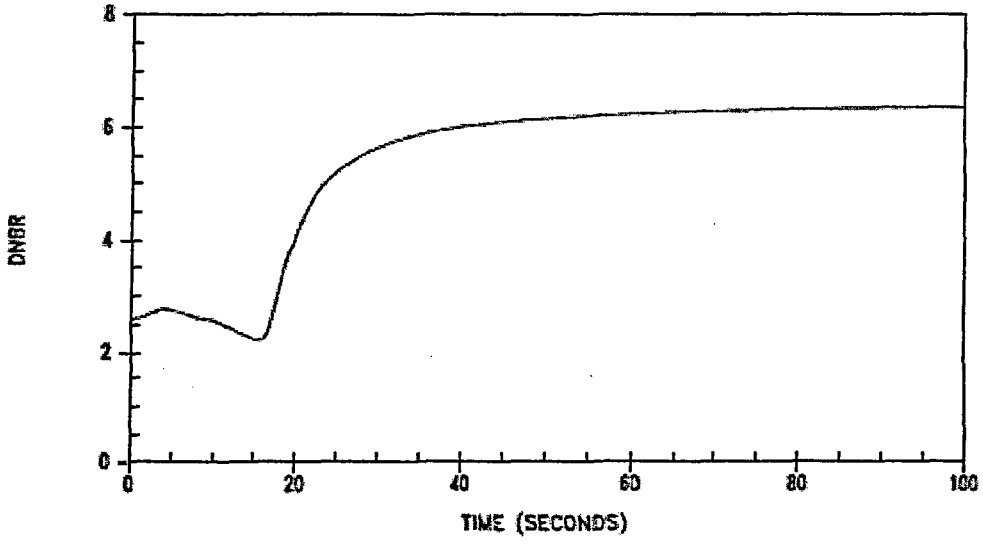
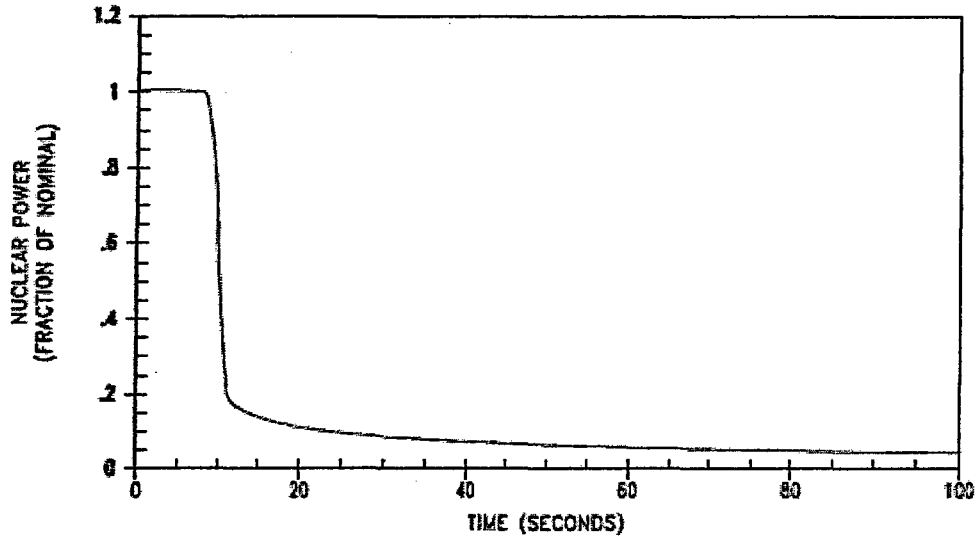


Figure 5.3.6-4A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
RCS Coolant Temperatures and DNBR versus Time



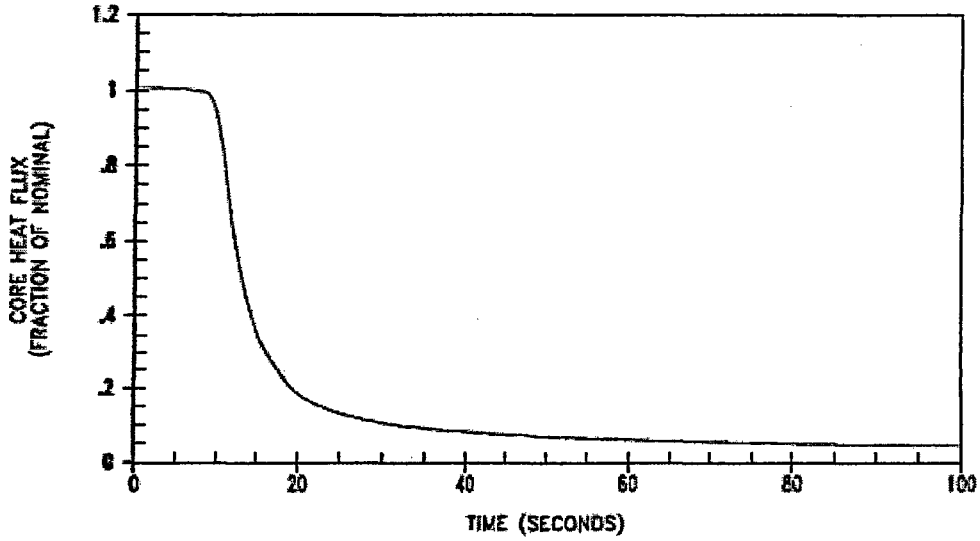
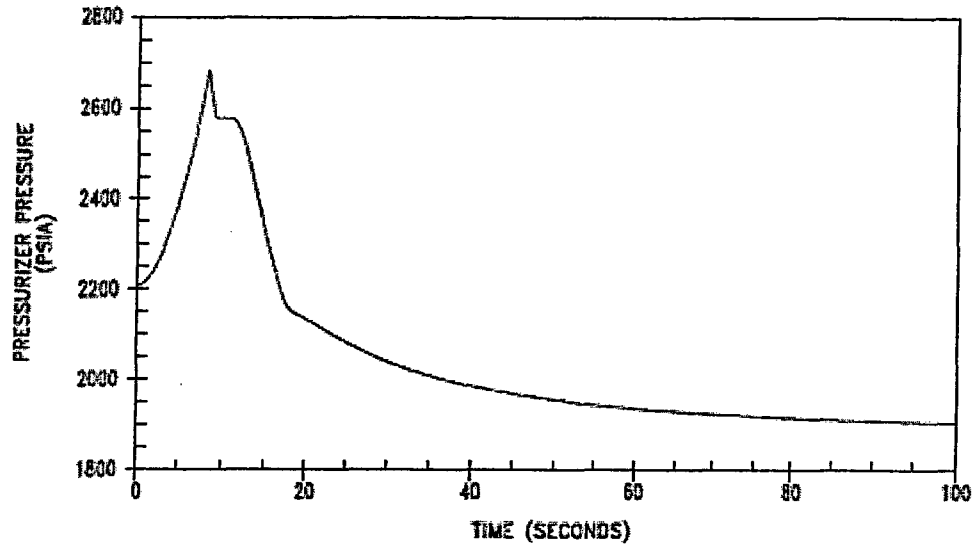


Figure 5.3.6-5A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Nuclear Power and Core Heat Flux versus Time



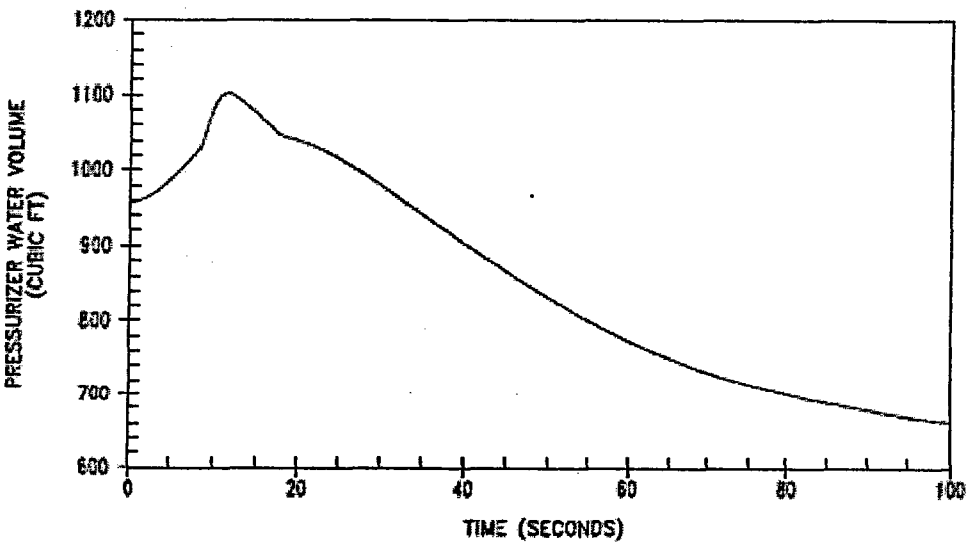


Figure 5.3.6-6A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure and Water Volume versus Time

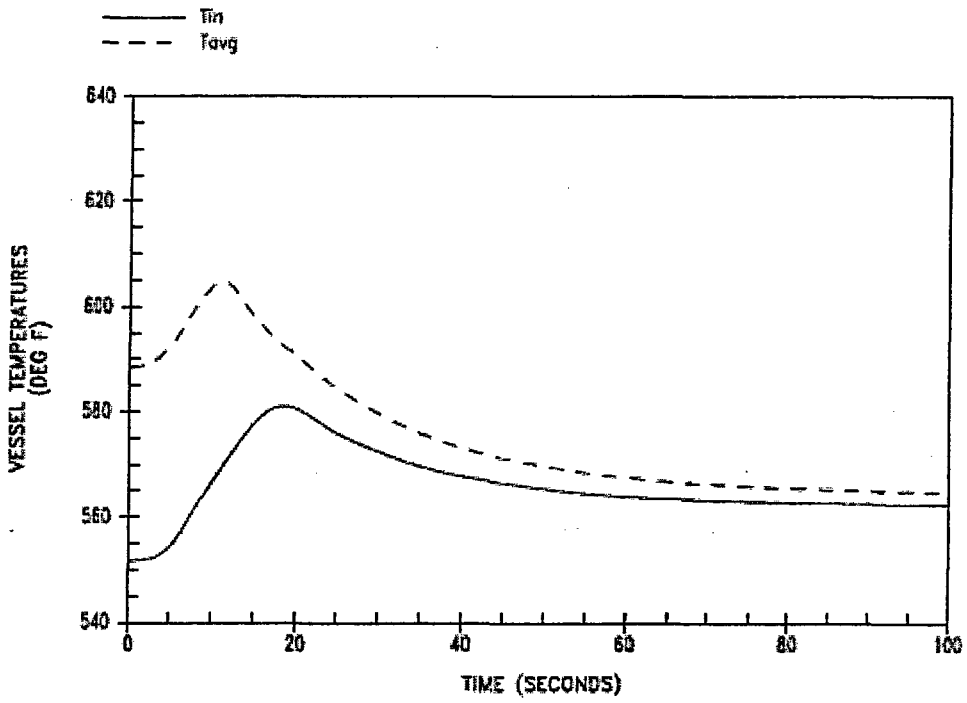
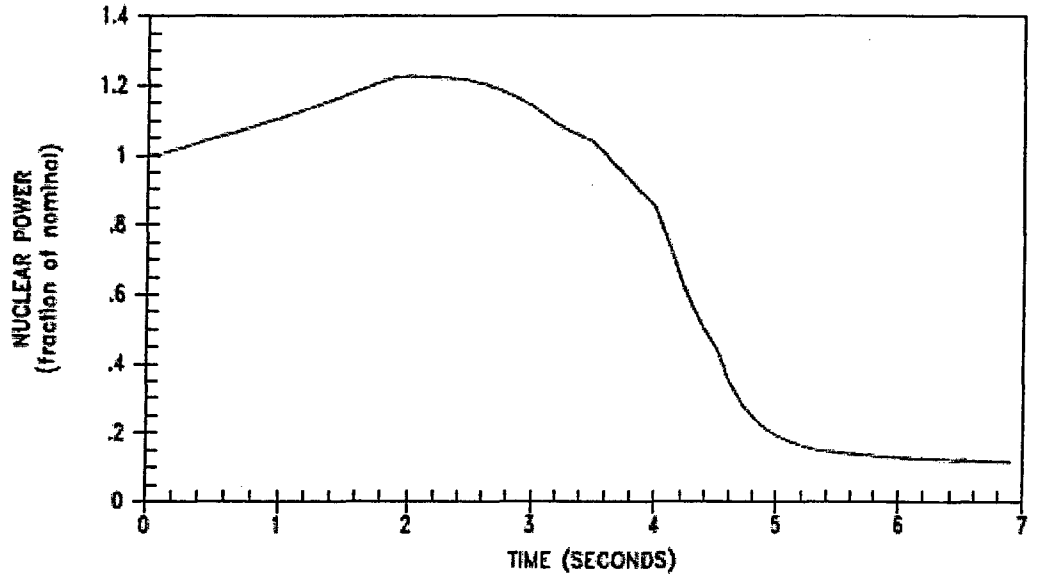


Figure 5.3.6-8A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
RCS Coolant Temperatures versus Time

Table 5.3.3-1A BVPS-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power		
Case	**Event**	**Time (sec)**
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (80 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Power Range High Neutron Flux – High Setpoint Reached	1.4
	Rods Begin to Fall	1.9
	Minimum DNBR Occurs	2.9
100% Power, Minimum Feedback, Slow RCCA Withdrawal (0.4 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Overtemperature Delta-T Trip Point Reached	104.1
	Rods Begin to Fall	106.1
	Minimum DNBR Occurs	107.1



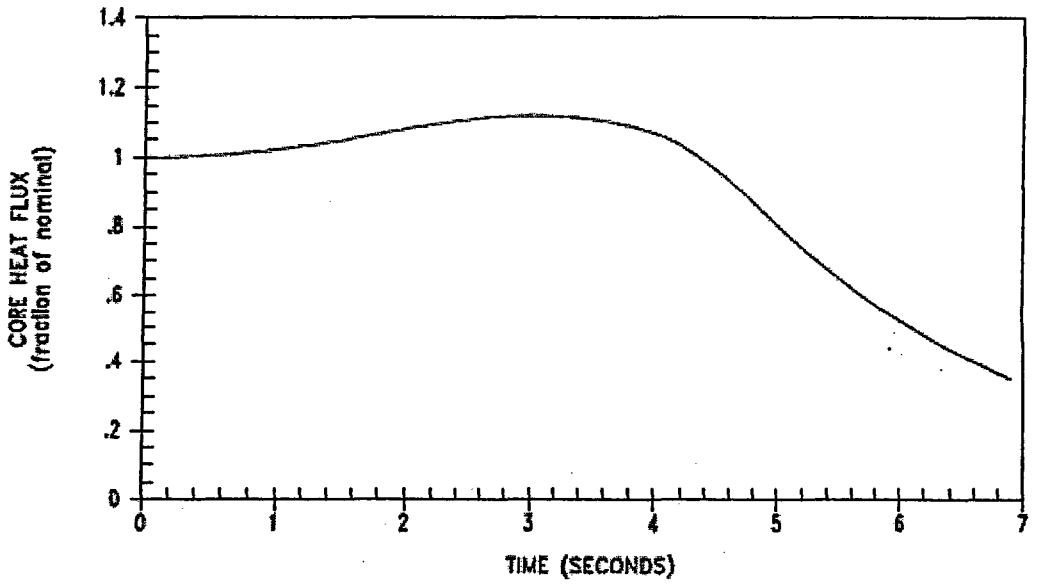
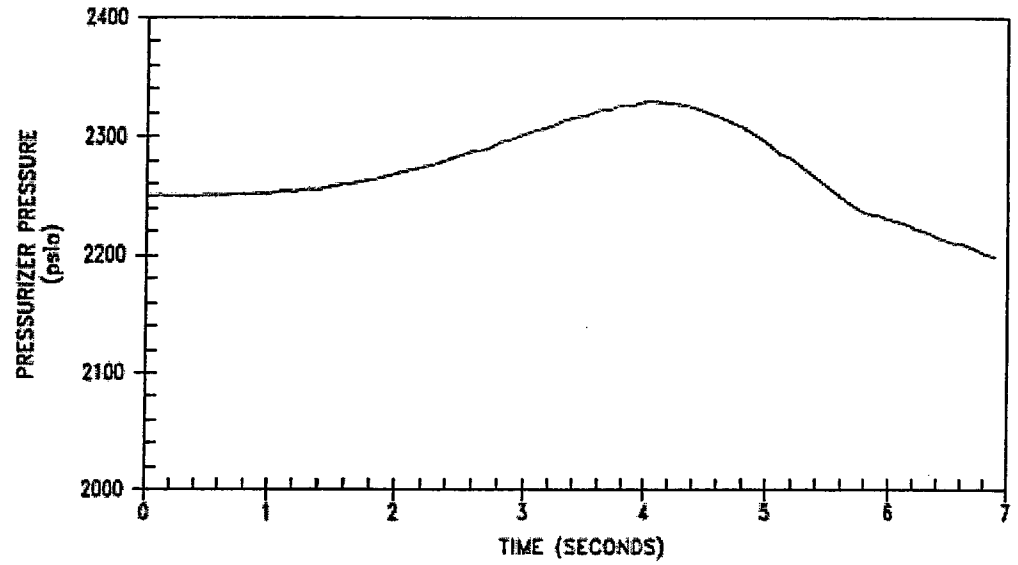


Figure 5.3.3-1A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Nuclear Power and Core Heat Flux versus Time



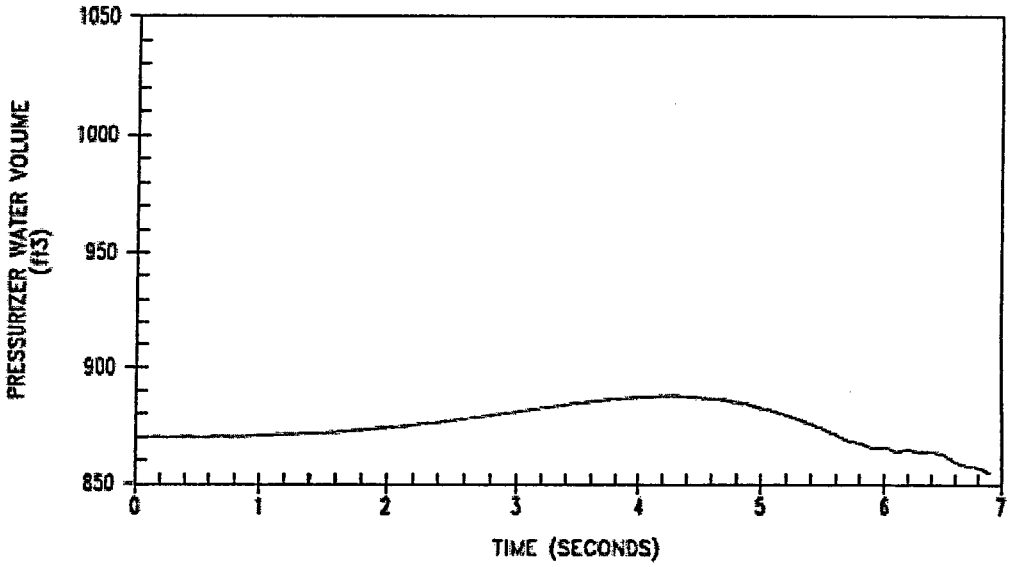
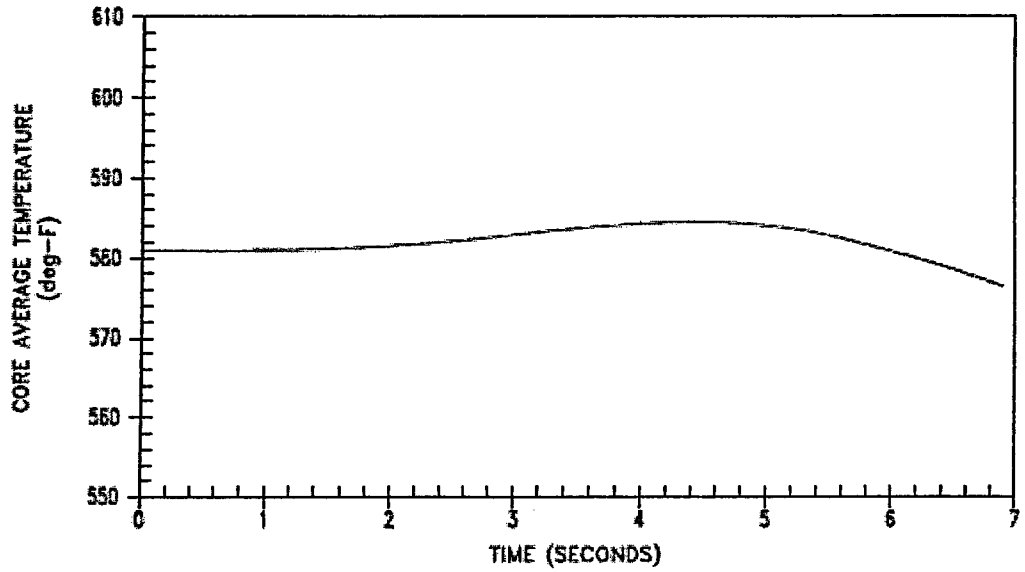


Figure 5.3.3-2A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Pressurizer Pressure and Water Volume versus Time



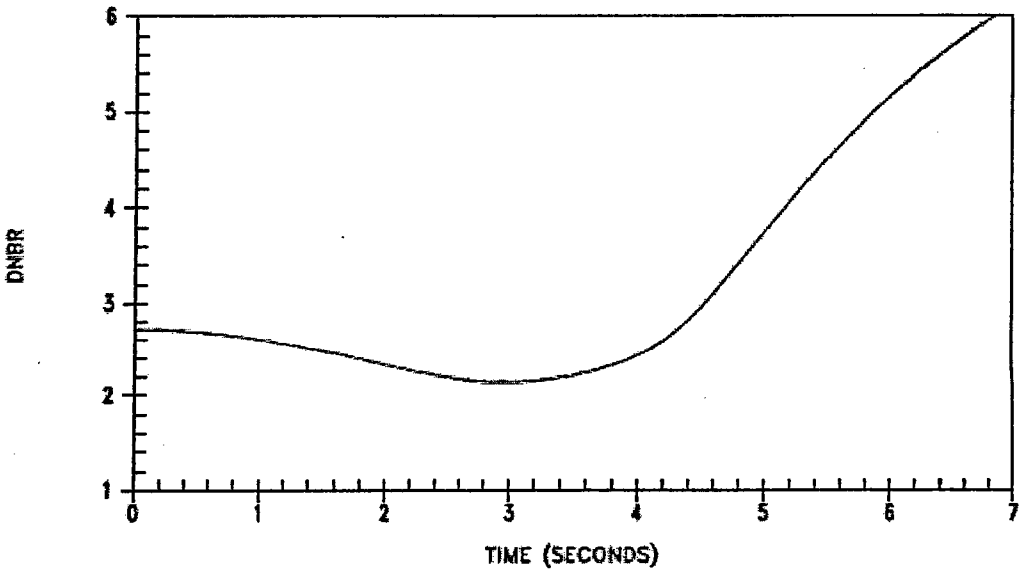
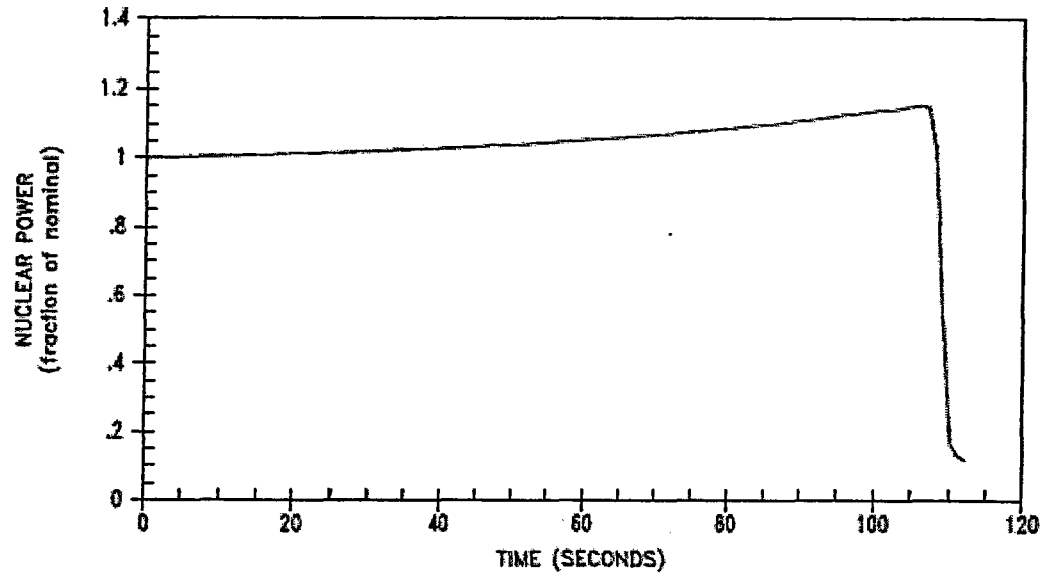


Figure 5.3.3-3A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Core Average Temperature and DNBR versus Time



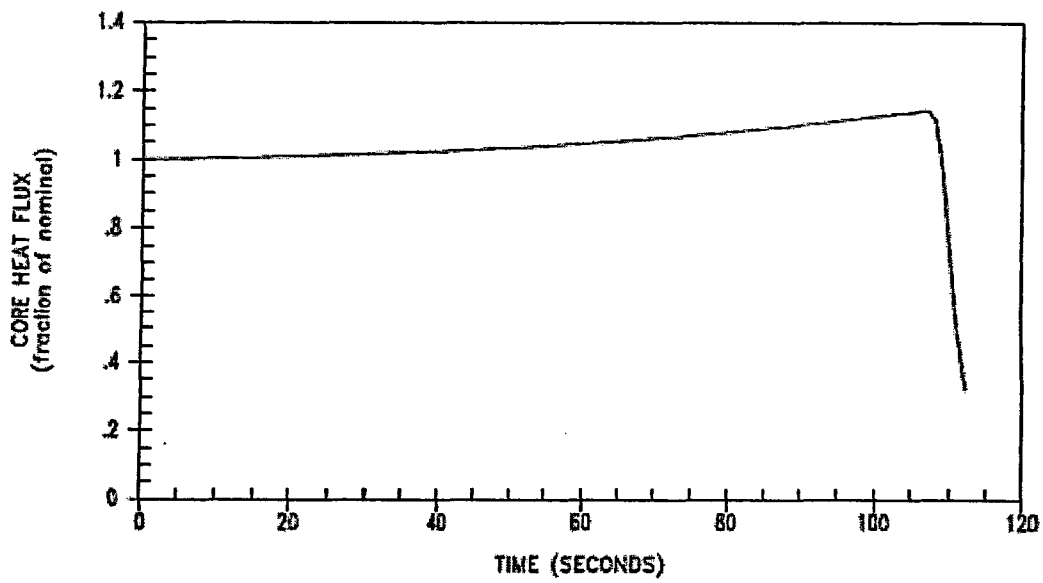
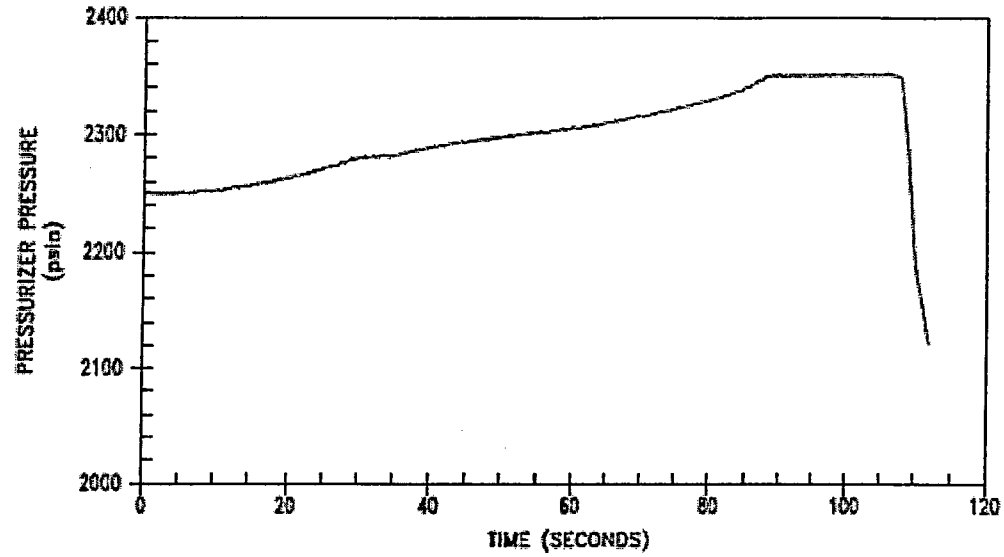


Figure 5.3.3-4A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Nuclear Power and Core Heat Flux versus Time



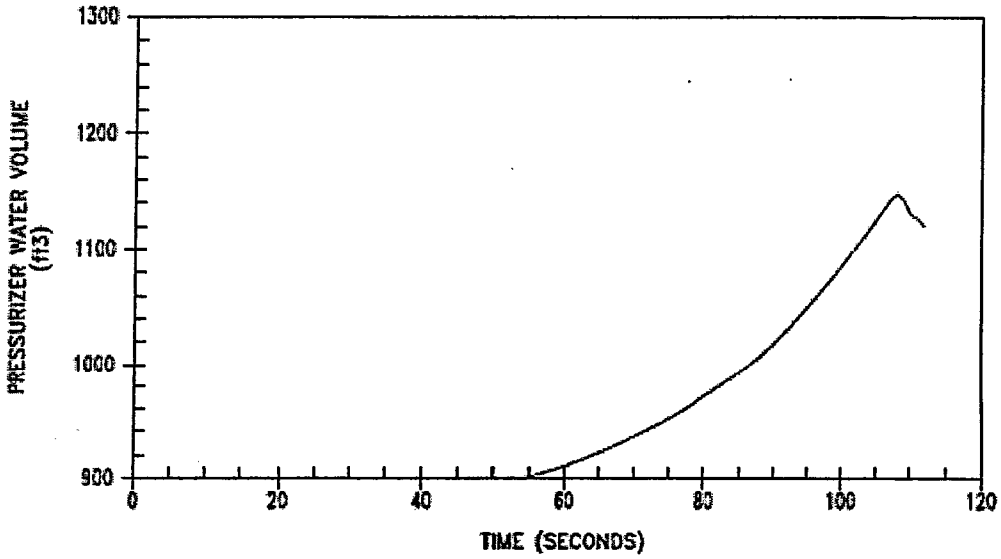
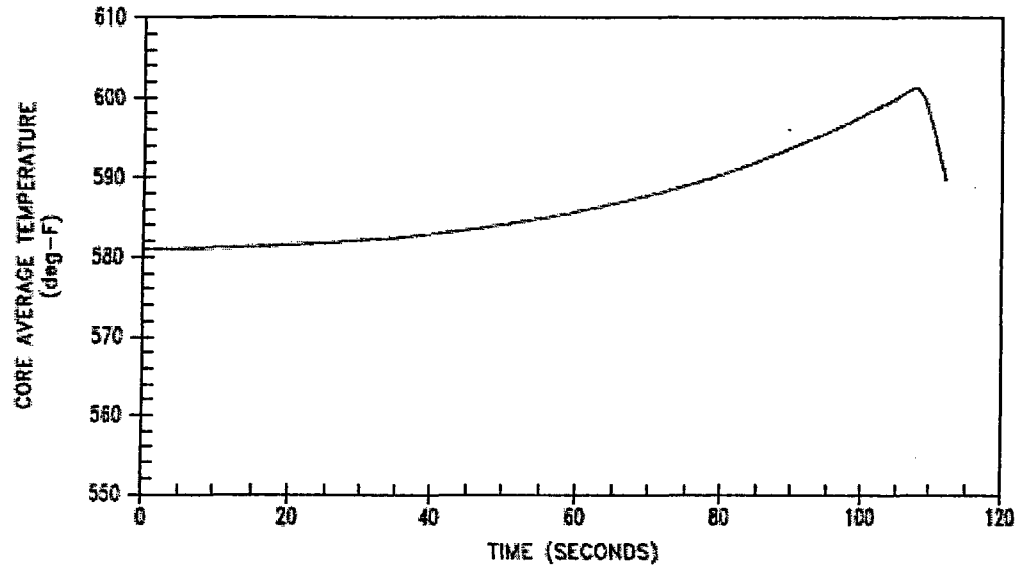


Figure 5.3.3-5A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Pressurizer Pressure and Water Volume versus Time



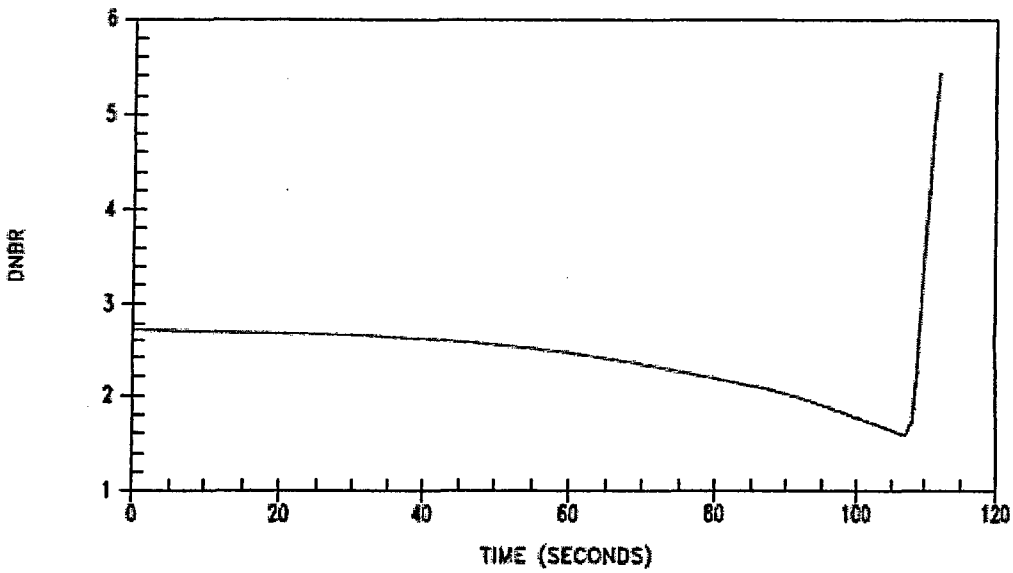


Figure 5.3.3-6A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Core Average Temperature and DNBR versus Time

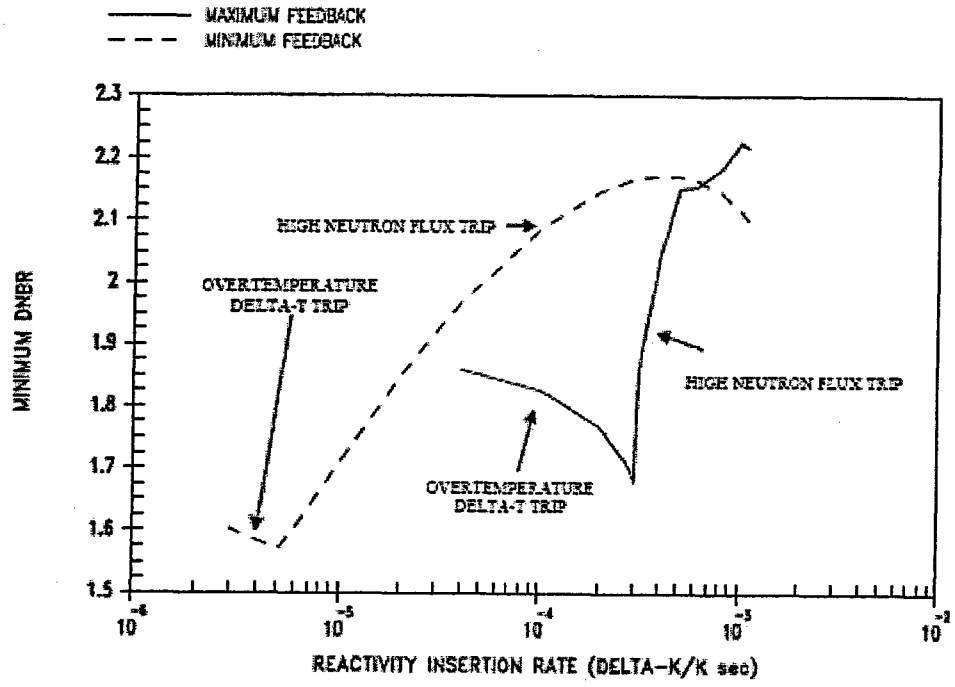


Figure 5.3.3-7A
BVPS-1 Rod Withdrawal at Power
100% Power
Minimum DNBR versus Reactivity Insertion Rate

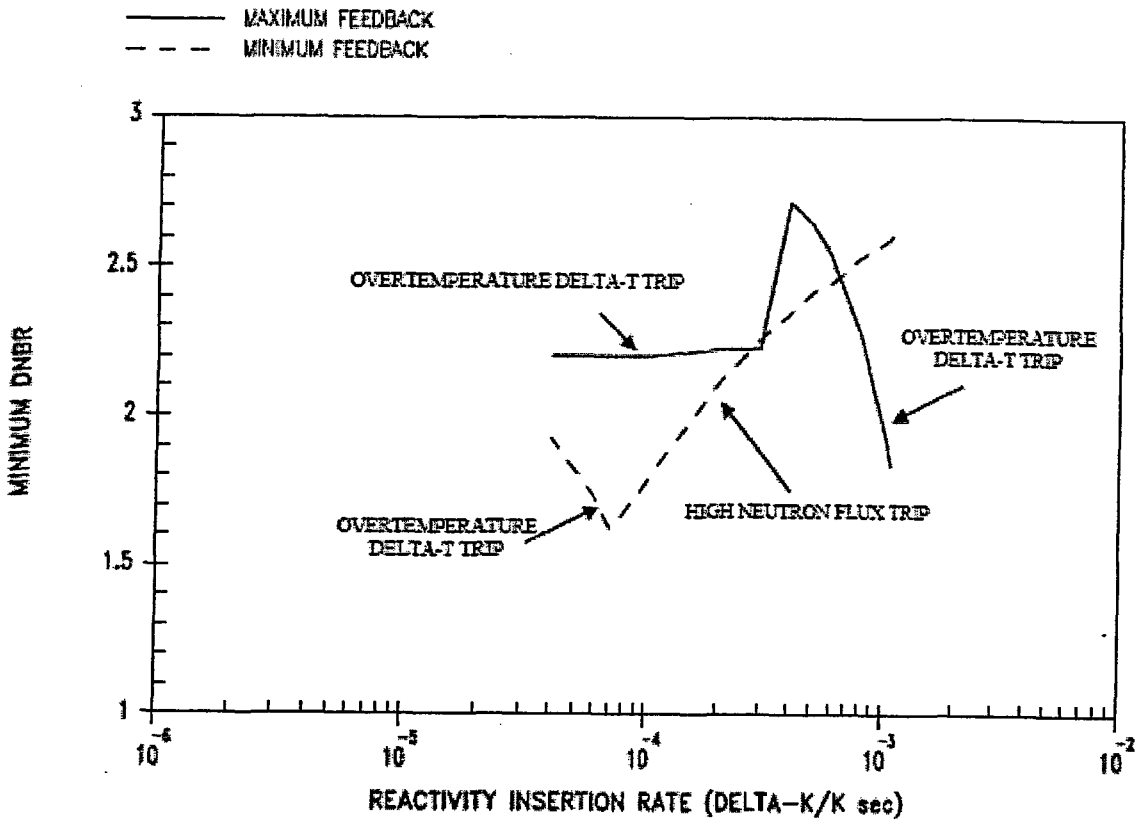


Figure 5.3.3-8A
BVPS-1 Rod Withdrawal at Power
60% Power
Minimum DNBR versus Reactivity Insertion Rate

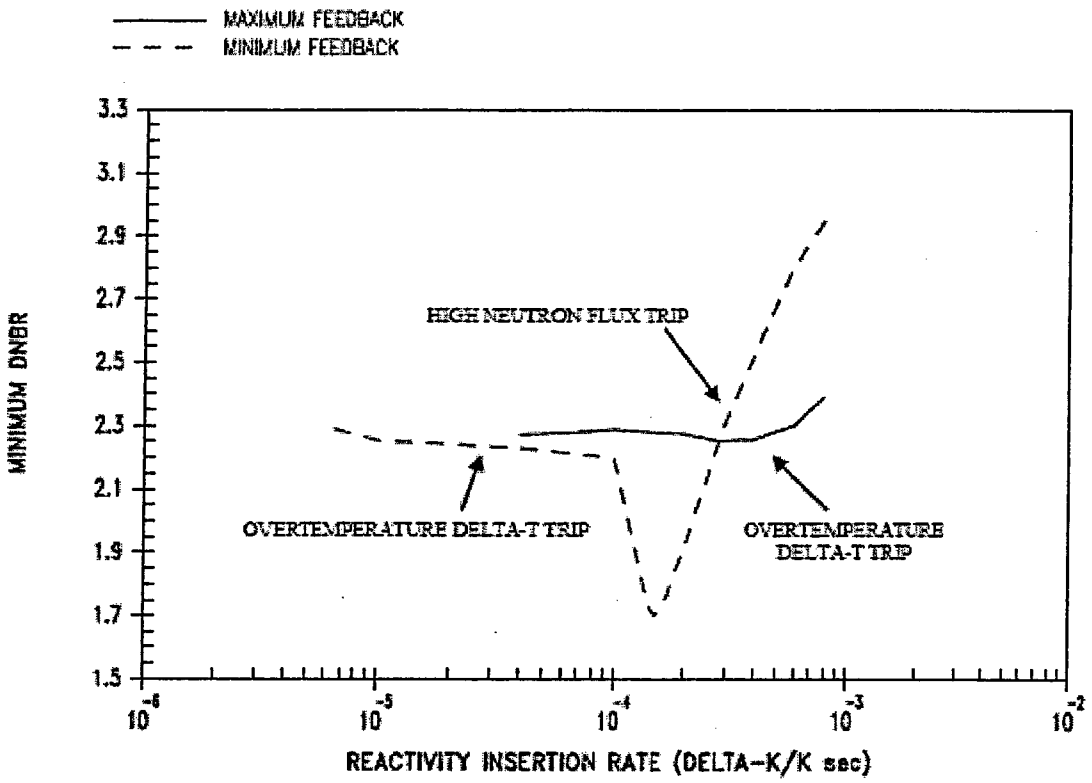


Figure 5.3.3-9A
BVPS-1 Rod Withdrawal at Power
10% Power
Minimum DNBR versus Reactivity Insertion Rate

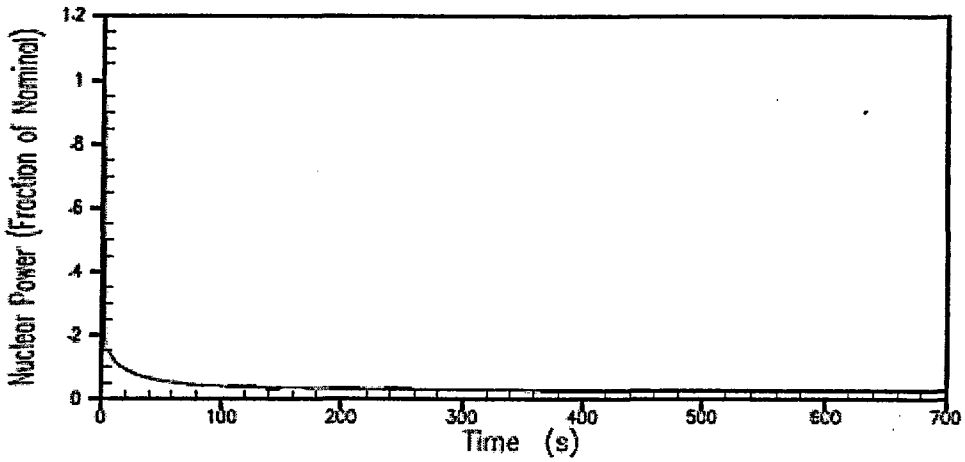


Figure V.1-1
BVPS-1 Spurious SI with Pressurizer Heaters On – Nuclear Power vs. Time

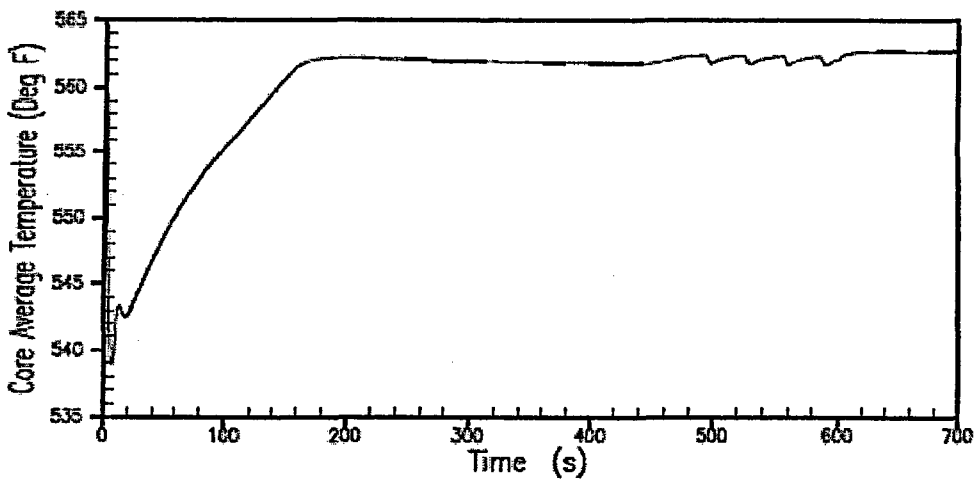


Figure V.1-2
BVPS-1 Spurious SI with Pressurizer Heaters On –
Core Average Coolant Temperature vs. Time

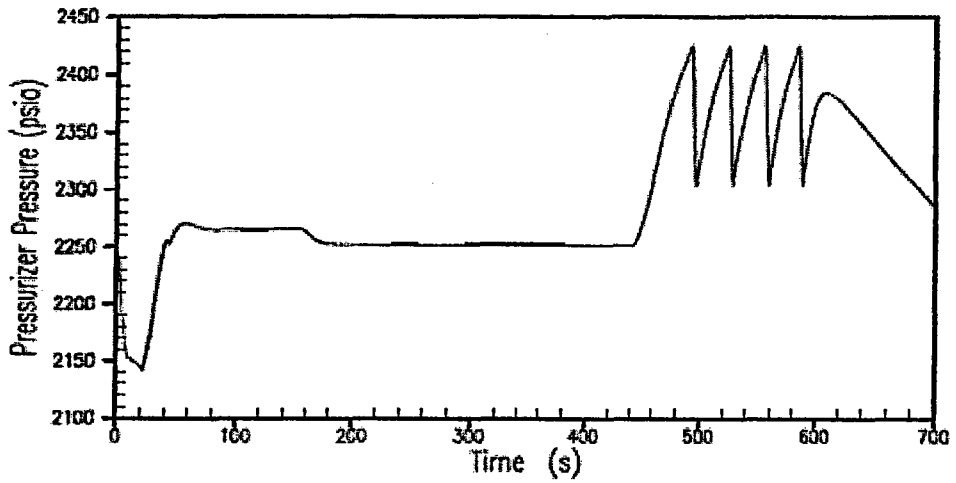


Figure V.1-3
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time

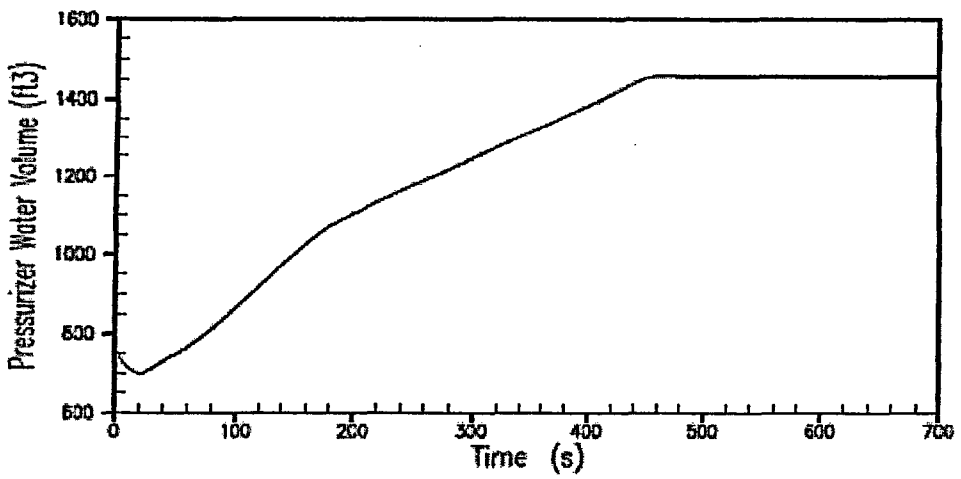


Figure V.1-4
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time

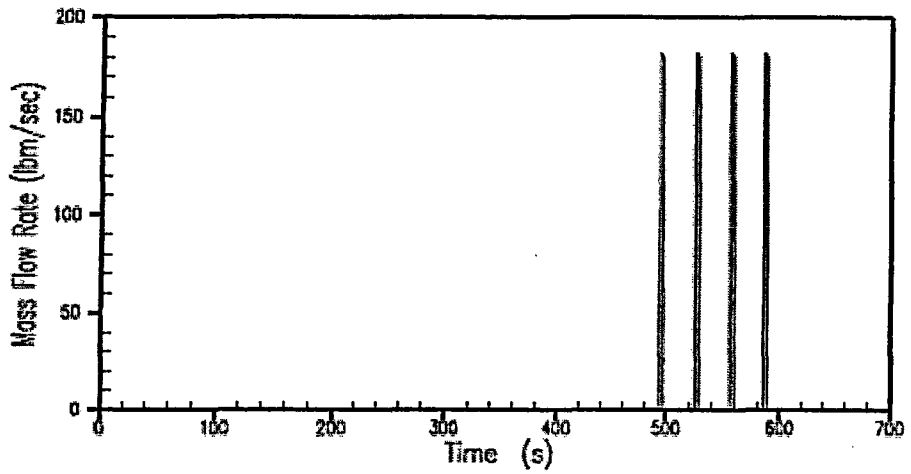


Figure V.1-5
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Safety Valve Water Relief vs. Time

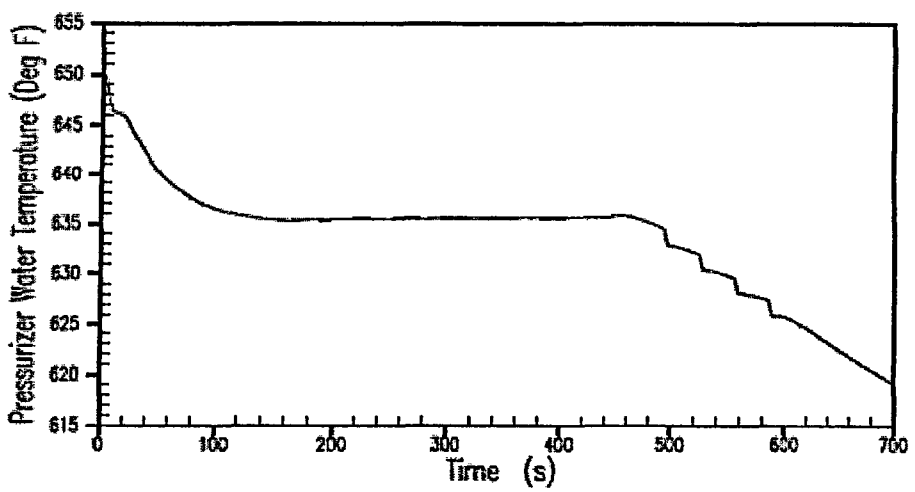


Figure V.1-6
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Water Temperature vs. Time

BEAVER VALLEY STATION

EXTENDED POWER UPRATE

SMALL BREAK LOCA

AND

POST-LOCA LONG TERM COOLING

L. W. WARD

ACRS COMMITTEE MEETING ON POWER UPRATES
ROCKVILLE, MD

APRIL 27, 2006

BEAVER VALLEY EPU

SBLOCA AND POST-LOCA LONG TERM COOLING

AGENDA

- INTRODUCTION
  - BEAVER VALLEY ECCS
  - APPROACH TO CONTROL PRECIPITATION
- LARGE BREAK LOCA
  - POST-LOCA LONG TERM COOLING (BORIC ACID PRECIPITATION)
- SMALL BREAK LOCA
  - SHORT TERM BEHAVIOR (PCT & CLAD OXIDATION)
  - POST-LOCA LONG TERM COOLING (BORIC ACID PRECIPITATION)
- CONCLUSIONS

INTRODUCTION

o BEAVER VALLEY ECCS

- THREE LOOPS, 2917.4 MWT

- 625 PSIA ACCUMULATORS

- SWITCH TO SIMULTANEOUS INJECTION (HPSI)

- COLD LEG BREAK IS LIMITING FOR BORIC ACID PRECIPITATION

CONTROL OF BORIC ACID

- o LARGE BREAKS

  - RE-ALIGN HPSI TO SIMULTANEOUS HOT AND COLD SIDE INJECTION

- o SMALL BREAKS

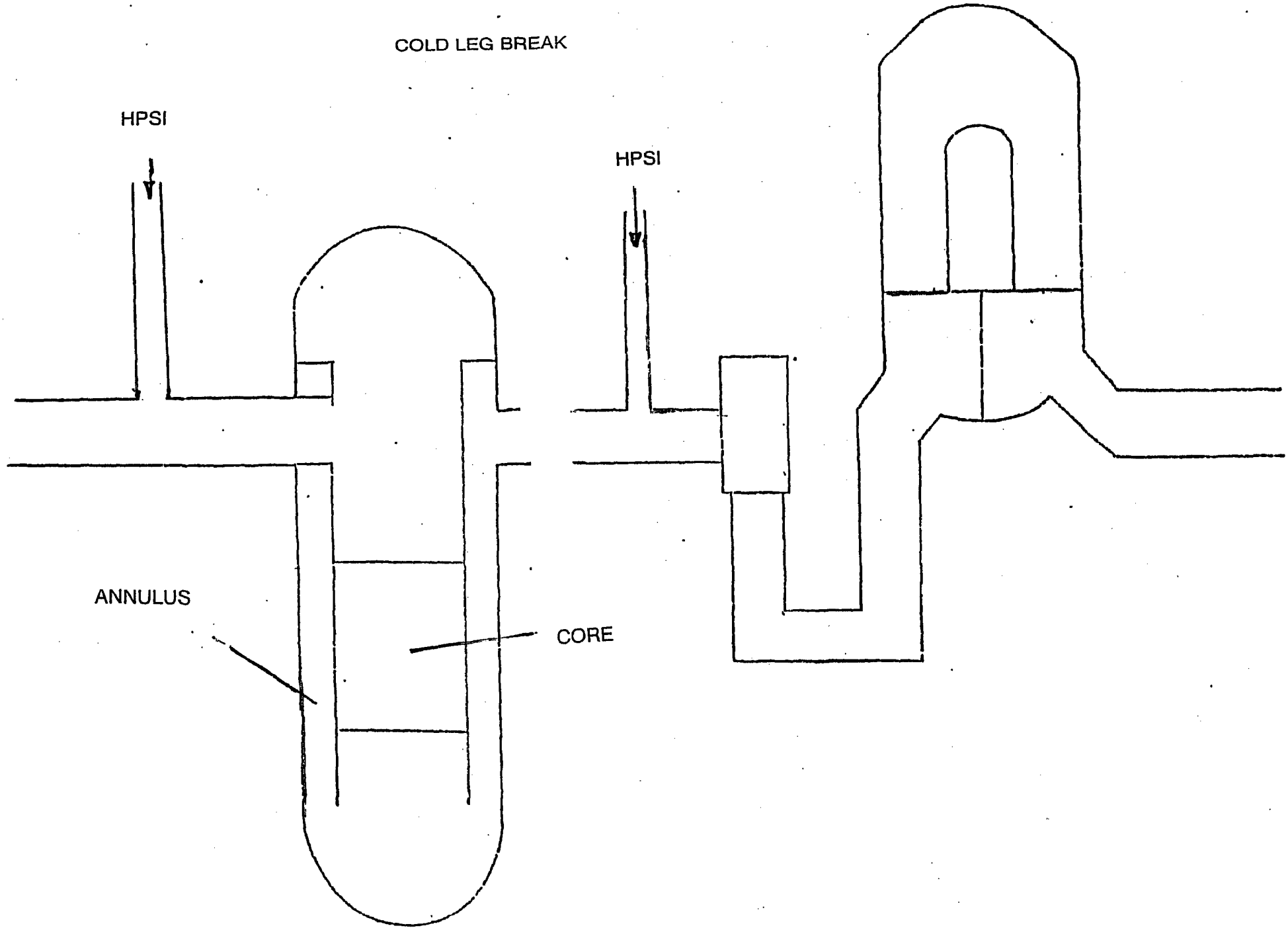
  - COOLDOWN RCS TO LOW PRESSURE CUT-IN (~ 140 PSIA)

  OR

  - REFILL RCS WITH ECC (RE-ESTABLISH SINGLE PHASE NAT. CIRC.)

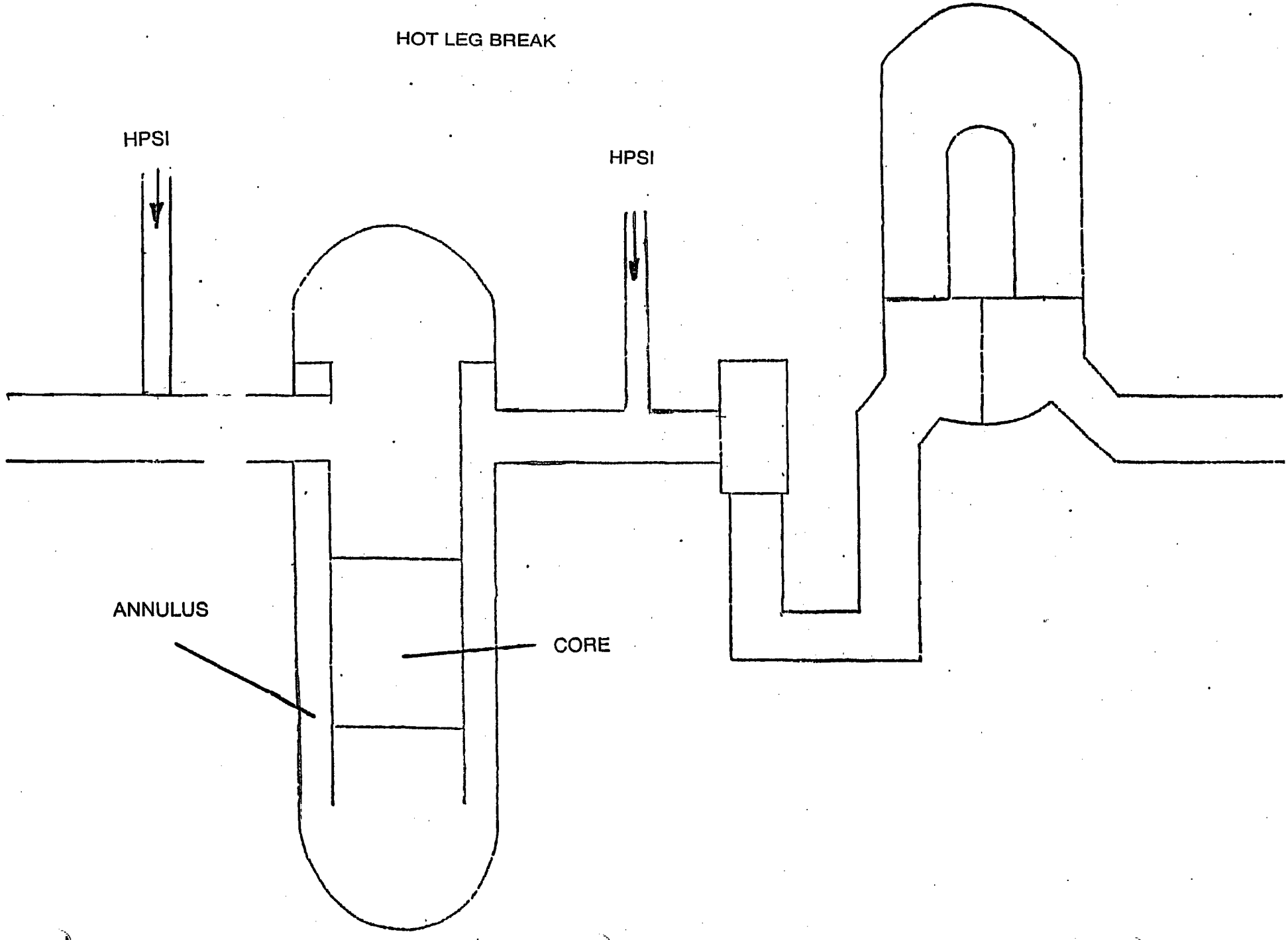
SIMULTANEOUS INJECTION

COLD LEG BREAK



SIMULTANEOUS INJECTION

HOT LEG BREAK

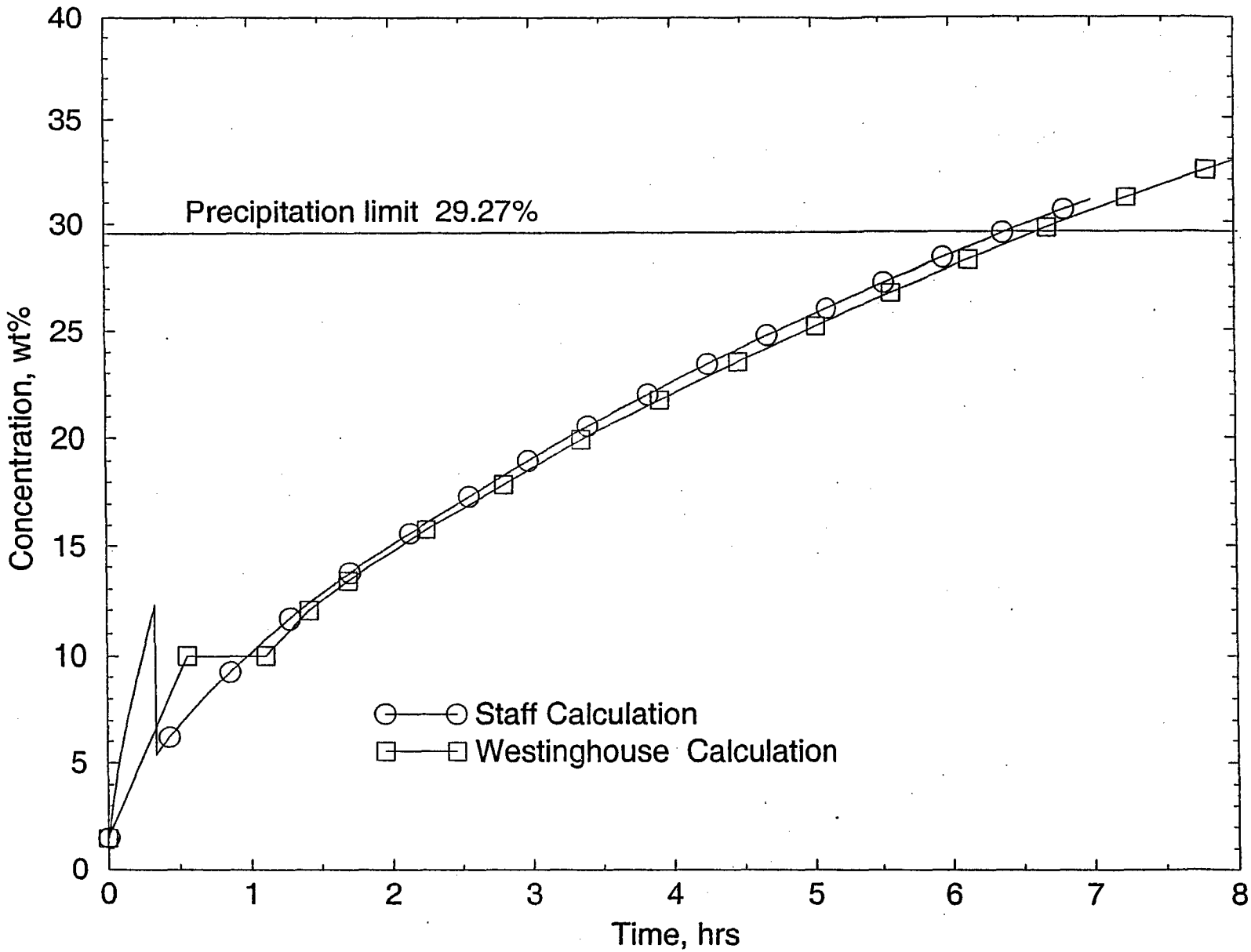


LBLOCA POST-LOCA LONG TERM COOLING

- o MODEL ASSUMPTIONS
  - MIXING VOLUME 1/2 LP, CORE, AND UPPER PL. BELOW HOT LEG BE
  - 1971 ANS STANDARD DECAY HEAT CURVE PLUS 20%
  - PRECIPITATION LIMIT IS 29.27%
  - MIXING VOLUME CALCULATED AS FUNCTION OF TIME
  - RWST & SIT CONCENTRATIONS OF 2600 PPM
- o COLD LEG BREAK LIMITING FOR PRECIPITATION
- o INITIATE SIMULTANEOUS INJECTION BEORE PRECIPITATION OCCURS
  - STAFF CALCULATION CONFIRMS LICENSEE 6.5 HR TIME TO REACH 29.27% LIMIT
  - VERIFIES 6.0 HR TIME TO SWITCH TO SIMULTANEOUS INJECTION
  - TIMING IS CALCULATED ON CONSERVATIVE BASIS

Boric Acid Concentration vs Time

Beaver Valley Unit 2, LBLOCA



SMALL BREAK LOCA SHORT TERM BEHAVIOR

- o INVESTIGATED ONLY INTEGER BREAK SIZES
  - ONE, TWO, THREE, FOUR, FIVE, & SIX INCH DIA BREAKS(
  - 0.0055, 0.0218, 0.049, 0.0893, 0.136 FT^2 CLB's

    SPECTRUM TOO COARSE TO IDENTIFY WORST BREAK

    BREAKS BETWEEN TWO & THREE ARE MORE LIMITING

    LICENSEE EVALUATED ADDITIONAL BREAKS

    WORST BREAK 2.75 INCH

    1917 °F PCT (VS 1759 °F FOR TWO INCH DIA)
- o LICENSEE MODEL ASSUMED ALL LOOP SEALS CLEAR FOR ALL SBLOCA'S
- o MODIFICATIONS AS A RESULTS OF INTEGER BREAK SIZE RE-ANALYSIS AND USING STAFF APPROVED NOTRUMP SBLOCA MODEL

  - INCREASED SIT COVER PRESSURE FROM 595 TO 625 PSIA

  - MODIFIED HPSI PUMPS TO PROVIDE ~ 5% ADDITIONAL FLOW (EPU)
- o IMPROVES MARGINS FOR ECCS ANALYSES

o STAFF ANALYSIS

- CONFIRMED LICENSEE PCT OF 1917 °F VS 1907 °F STAFF CALCULATION

  RELAP5/MOD3 (24 AXIAL CELLS IN CORE PLUS HOT BUNDLE MODEL)

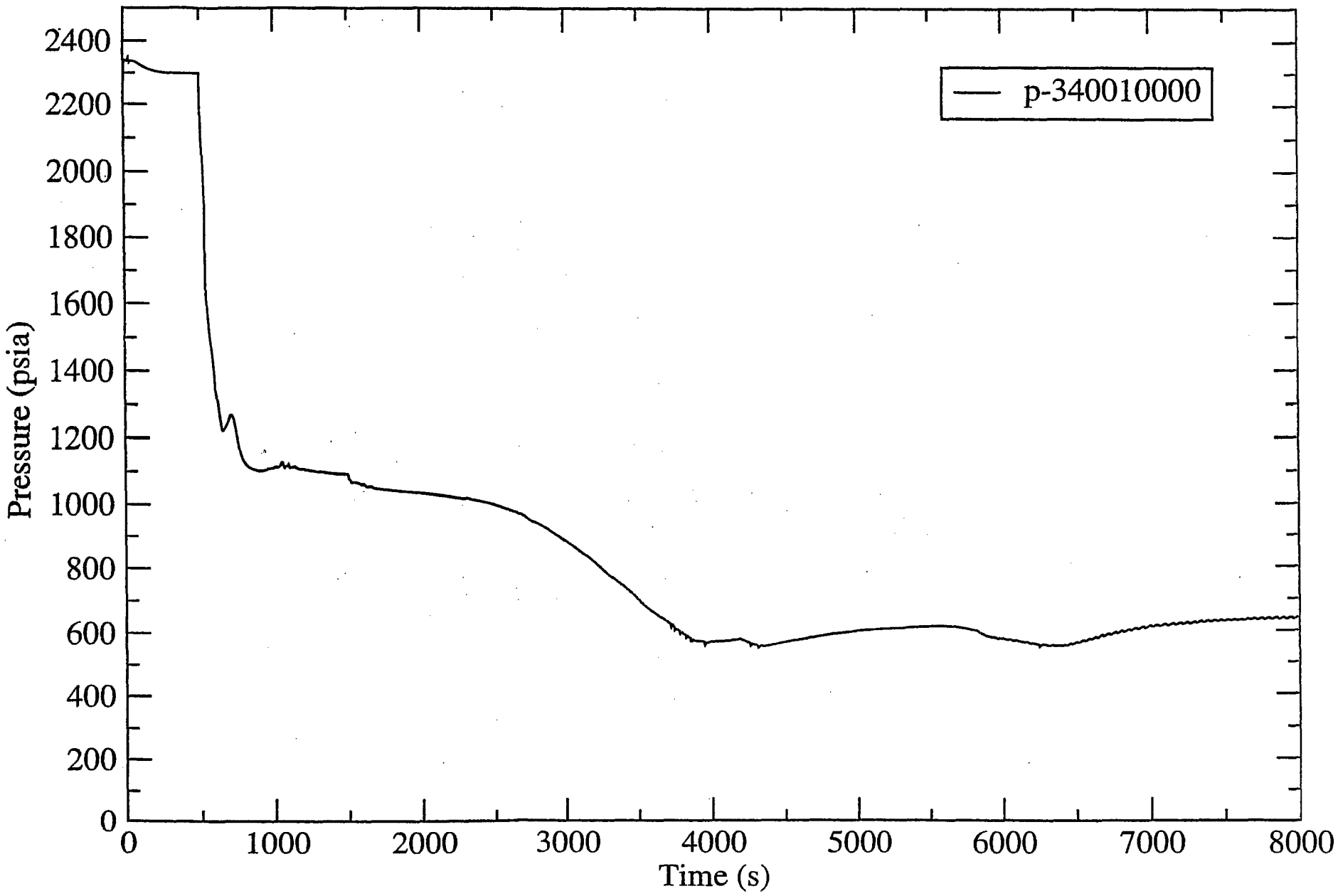
  2917.4 MWT

  14.0 KW/FT

STAFF CALCULATIONS ALSO CONFIRMED BREAKS ON TOP OF COLD LEG AND SEVERED ECC LINE ARE LESS LIMITING

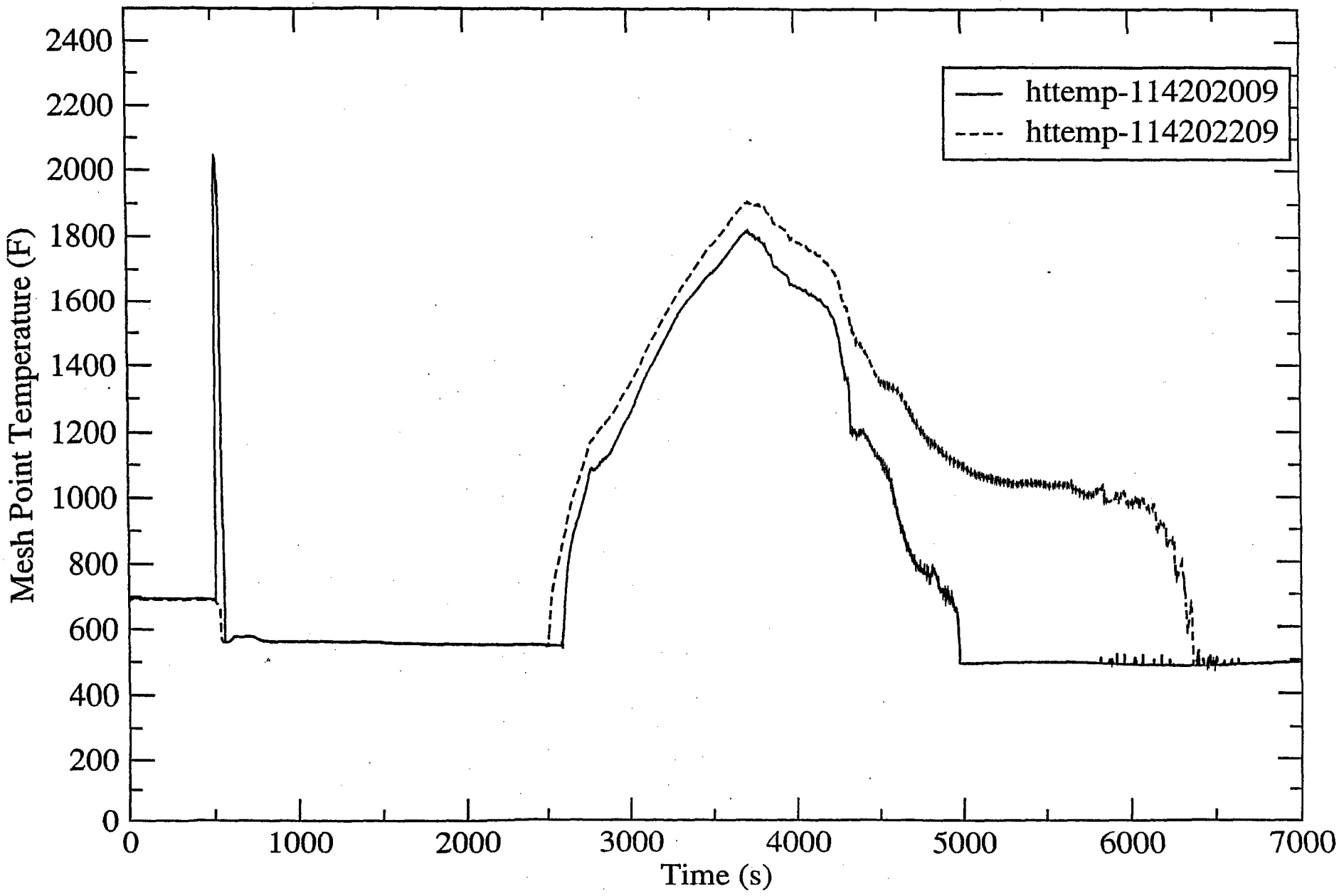
RCS Pressure vs. Time

Beaver Valley EPU 2.75 inch SBLOCA



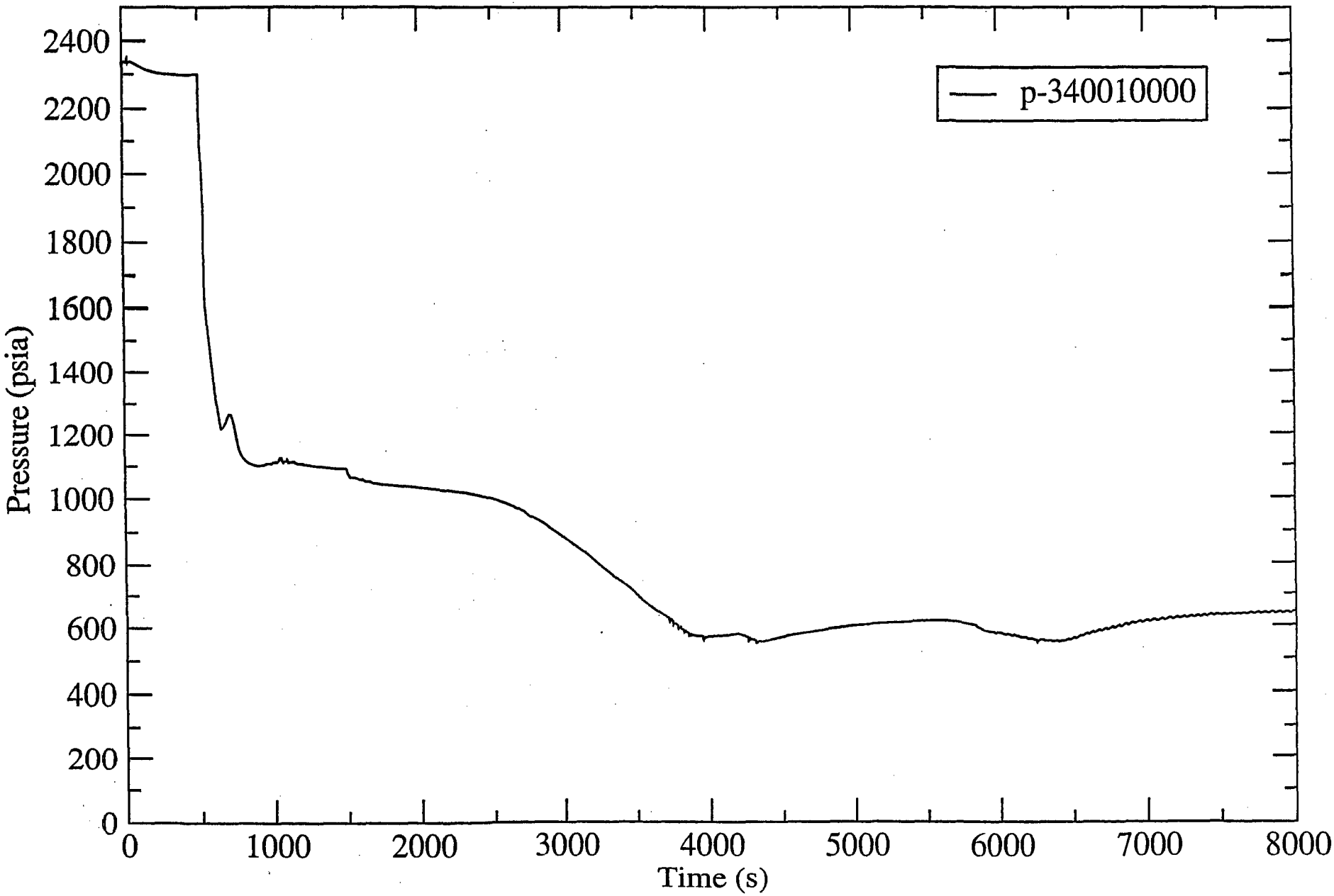
PCT vs Time

Beaver Valley EPU 2.75 inch SBLOCA



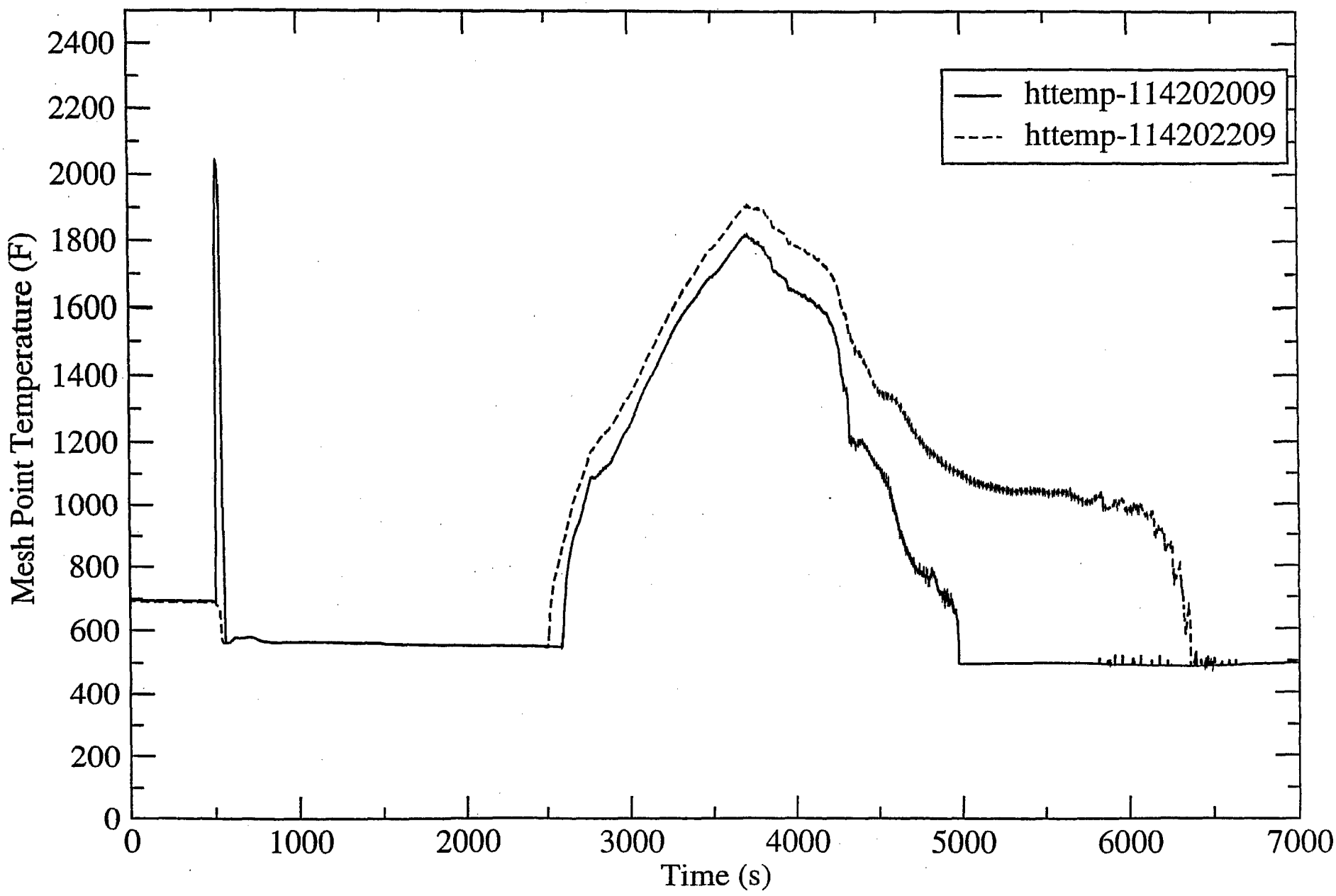
RCS Pressure vs. Time

Beaver Valley EPU 2.20 inch SBLOCA



PCT vs. Time

Beaver Valley EPU 2.20 inch SBLOCA



SBLOCA SHORT TERM BEHAVIOR (CON'T)

- o STAFF CALCULATION OF SMALL BREAKS ALSO SHOWED FIRST PEAK
  - EARLY CHF CONDITION
  - FIRST PEAK IS ~2000 °F WITH STAFF MODEL
  - PCT REMAINS WITHIN 10CFR50.46
- o STAFF WILL FOLLOW UP WITH GENERIC INVESTIGATION OF SBLOCA ANALYSIS MODELS/ASSUMPTIONS AND POTENTIAL FOR EARLY CHF

SMALL BREAK LOCA (LONG TERM COOLING)

o CONTROL OF BORIC ACID BUILD-UP

- BOILING FOR EXTENDED PERIODS

- PRESSURE REMAINS HIGH AND PRECLUDES CORE FLUSH

RCS PRESSURE NEEDS TO BE REDUCED LOW ENOUGH TO FLUSH CORE

OR

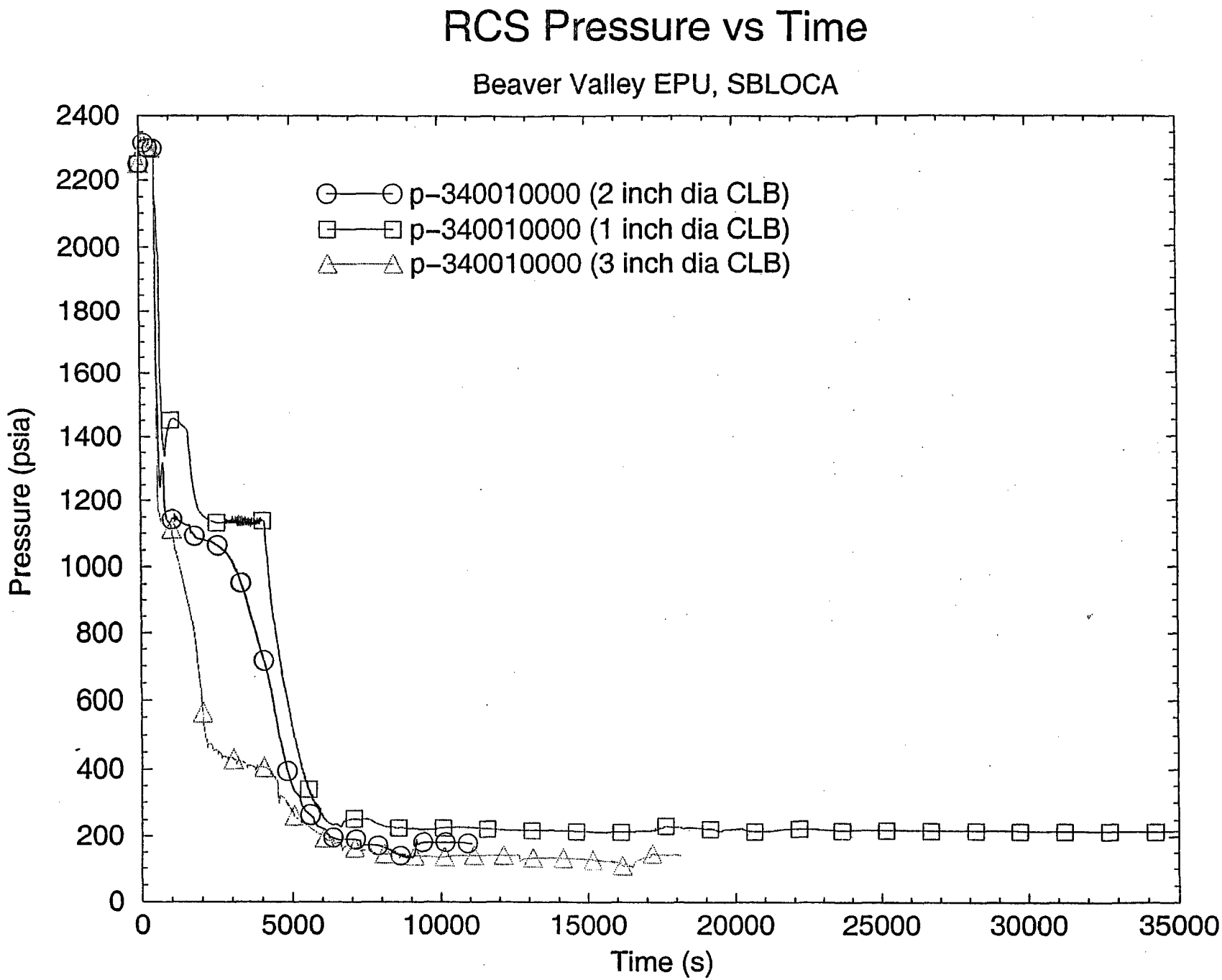
DEMONSTRATE REFILL OF RCS

- STAFF AUDIT CALCULATIONS SHOW RCS REFILLS

1.8 HRS	1 INCH DIA CLB
2.5 HRS	2 INCH DIA CLB
4.7 HRS	3 INCH DIA CLB

- RCS PRESSURE BELOW 100 PSIA FOR 4 INCH DIA CLB

FLUSHES CORE


RCS Pressure vs Time
Beaver Valley EPU, SBLOCA
p–340010000 (2 inch dia CLB)
p–340010000 (1 inch dia CLB)
p–340010000 (3 inch dia CLB)
Pressure (psia)
Time (s)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
0
5000
10000
15000
20000
25000
30000
35000

SMALL BREAK LOCA POST-LOCA LONG TERM COOLING (CON'T)

- EOP MODIFICATIONS

  COOLDOWN BEGINS NO LATER THAN ONE HR

  CAUTIONS TO OPERATORS TO PRECLUDE INADVERTENT DEPRESSURIZATION FOLLOWING LONG BOILING PERIODS

  EOP GUIDANCE ON EQUIPMENT AND TIMING FOR COOLDOWN

CONCLUSIONS

- o INTEGER BREAK SPECTRUM DOES NOT IDENTIFY WORST SMALL BREAK

- o EMPLOYED UNAPPROVED NOTRUMP SBLOCA MODEL

- o LICENSEE INCREASE SIT PRESSURE AND HPSI FLOW CAPACITY

- o STAFF RELAP5/MOD3 ANALYSIS CONFIRMED WORST SMALL BREAK

  SBLOCA WITHIN 10CFR50.46 LIMITS

- o STAFF CALCULATIONS

  CONFIRMED TIMING FOR BORIC ACID PRECIPITATION

  BOILING CAN LAST MANY HRS FOR SBLOCA
  (EQUIPMENT AND TIMING VERY IMPORTANT)

  IDENTIFIED NEED FOR EOP MODS

- o STAFF FINDS EPU SBLOCA SHORT TERM ANALYSES AND SBLOCA/LBLOCA LONG TERM COOLING ANALYSES MEET 10 CFR50.46 ACCEPTANCE CRITERIA

ACRS Subcommittee on Power Uprates

BEAVER VALLEY EPU CONTAINMENT REVIEW

Richard Lobel
Senior Reactor Systems Engineer
Office of Nuclear Reactor Regulation

April 25, 2006

CONTAINMENT CONVERSION

- February 6, 2006, NRC letter to FENOC approved the conversion of the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric

- As part of this proposal, the licensee included consideration of EPU and Unit 1 steam generator replacement

- A new analysis method, MAAP-DBA is introduced

Millstone Unit 3

- The Millstone Unit 3 containment was originally designed and operated as a subatmospheric containment.

- Millstone Unit 3 containment converted to an atmospheric containment in 1991.

Beaver Valley Containment Normal Operating Conditions

- <u>Subatmospheric Containment Pressure</u>: Defined by a technical specification curve to between 8.9 psia (Unit 1) or 9.0 psia (Unit 2) and 10.5 psia
- <u>Atmospheric Containment Pressure</u>: Between 12.8 psia and 14.2 psia
- <u>Atmospheric Containment Temperature</u>:

  $70\ F \leq T \geq 105\ F$

Subatmospheric Containment Design Bases

- Peak Pressure ≤ 45 psig
- *Containment shall be depressurized in one hour*
- *Once depressurized, containment remains subatmospheric*
- Containment liner temperature ≤ 280 F
- Subcompartments maintain structural integrity
- Minimum containment pressure ≥ 8 psia
- Unit 1 credits containment accident pressure for ECCS pump NPSH. Unit 2 does not.

Atmospheric Containment Design Bases

- Peak Pressure ≤ 45 psig
- *Containment pressure < 50% of peak within 24 hours*
- Containment liner temperature ≤ 280 F
- Subcompartments maintain structural integrity
- Minimum containment pressure ≥ 8 psia
- Unit 1 credits containment accident pressure for ECCS pump NPSH. Unit 2 does not.

LARGE BREAK LOCA

- For time < 1 hour: mass and energy release to containment calculated with NRC-approved Westinghouse methods
- For time > 1 hour: mass release calculated with same NRC-approved Westinghouse methods. Energy calculated with MAAP-DBA. (Staff performed audit calculations with RELAP to assess this approach. Good agreement. See Appendices to Staff SER.)
- Containment parameters calculated with MAAP-DBA
- Conservative inputs and assumptions

LOCA Results

Unit 1:

Power = 100% (EPU)

Break: Double Ended Hot Leg (DEHL)

Peak Containment Pressure = 43.3 psig

Corresponding containment atmosphere temperature: 267.8

Unit 2:

Power = 100% (EPU)

Break: Double Ended Hot Leg (DEHL)

Peak Containment Pressure = 44.9 psig

Corresponding containment atmosphere temperature: 270.1

Main Steam Line Break Accident

- Mass and Energy (M&E) release calculated with NRC-approved Westinghouse methods (WCAP 8822P-A
- Replacement SGs have flow restriction in steam generator nozzle (limits the break area)
- Cavitating venturis limit AFW flow to faulted SG for both units
- Spectrum of break sizes and power levels
- Both steam generator designs for Unit 1 considered
- Conservative assumptions

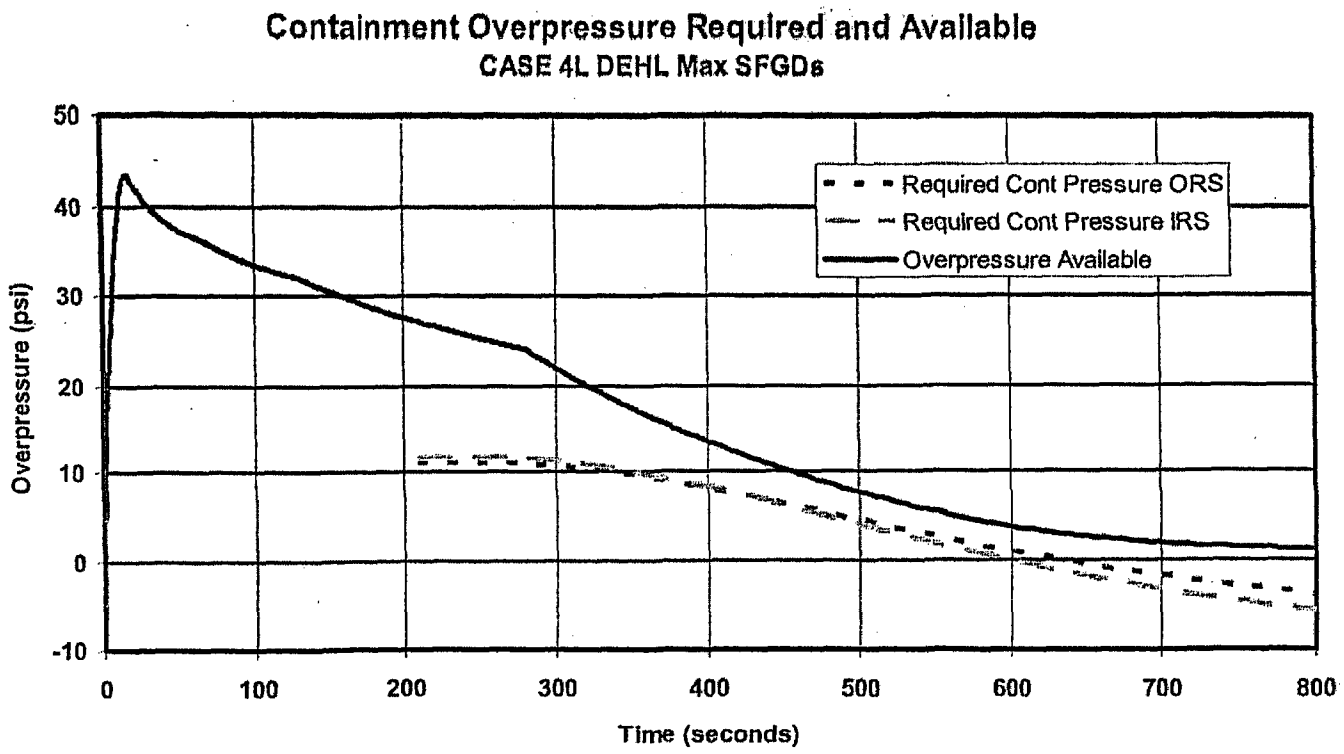
Peak Containment Liner Temperature

- LOCA produces higher containment pressures
- MSLB produces higher containment atmosphere temperatures
- For conservatism, heat transfer coefficient multiplied by 4 (consistent with SRP)
    - Unit 1: 254.1 F
    - Unit 2: 247.7 F
- Acceptance criterion 280 F

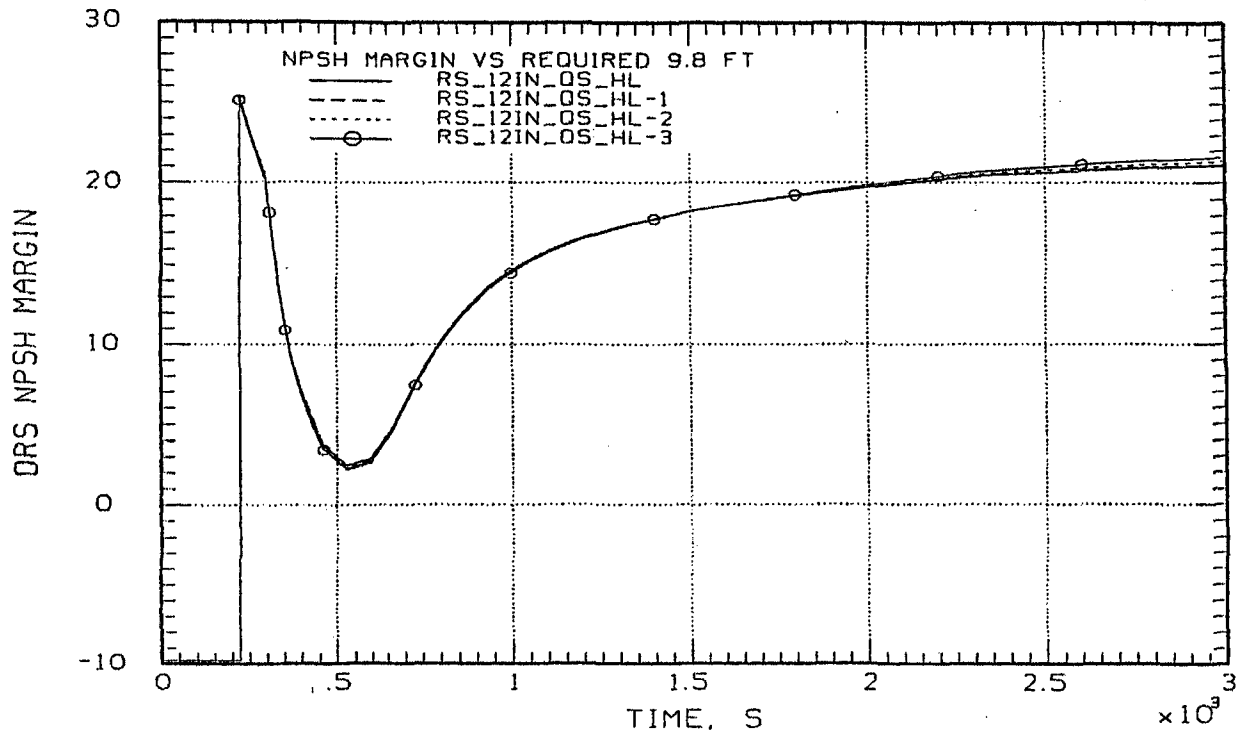
Sump Temperature and Net Positive Suction Head (NPSH)

- SRP 6.2.2 states that credit for containment accident pressure in determining available NPSH is acceptable for subatmospheric containments
- The Beaver Valley Unit 1 recirculation spray pumps satisfy this guidance at current power and at EPU
- Recirculation spray pumps start shortly after accident initiation when sump level is low and sump temperature is high
- Beaver Valley Unit 2 recirculation spray and ECCS pumps do not credit containment accident pressure for NPSH
- More realistic analysis assumptions do not eliminate crediting containment accident pressure

Sump Temperature and Net Positive Suction Head (NPSH)



Sump Temperature and Net Positive Suction Head (NPSH)



Sump Temperature and Net Positive Suction Head (NPSH)

- Pump testing with a pump hydraulically similar in design to Beaver Valley inside recirculation spray pump concluded that pumps will operate in stable condition without cavitation damage.

Sump Temperature and Net Positive Suction Head (NPSH)

- Staff accepted credit for containment accident pressure for available NPSH based on:

  Limited time needed

  (< 400 sec for limiting case)

  (< 20 minutes for non-limiting case)

  Containment pressure will be less than atmospheric pressure during operation

  Pump test data which demonstrates no damage to Beaver Valley pumps in cavitation

  No impact on EOPs

MAAP-DBA

- As part of containment conversion, licensee proposes to use the MAAP-DBA computer code for:

  containment analyses

  (LBLOCA, SBLOCA, MSLB)

  LBLOCA long term energy release

  SBLOCA mass and energy release

MAAP-DBA

MAAP-DBA is used to calculate the following containment conditions:

Single Node:

peak containment pressure
peak containment atmosphere temperature
maximum liner temperature

Multiple Nodes:

Sump water temperature and level

MAAP-DBA VALIDATION

- MAAP-DBA compared well with other computer code calculations and with separate effects data and integral tests results.
- Both single node and multiple node models used in validation
- Validation discussed in:

  November 24, 2003 licensee letter

  June 2, 2004 submittal Section 9.0

  NRC Staff February 6, 2006, SER

Conclusion

- February 6, 2006 NRC letter to licensee found containment conversion at EPU conditions acceptable
- February 6, 2006 NRC letter to licensee approved MAAP-DBA for Beaver Valley atmospheric containment calculations for applications listed previously

Source Terms and Radiological Consequences Analyses

John Parillo
Health Physicist
Accident Dose Branch
Division of Risk Assessment
Office of Nuclear Reactor Regulation

Source Terms for Input into Radwaste Management Systems Analysis

- RS-001 Matrix 9, EPU SE Section 2.9.1
- Radiological source term in reactor coolant system analyzed for EPU conditions
- Source term continues to meet requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60

DBA Radiological Consequences Analyses

- RS-001 Matrix 9, EPU SE Section 2.9.2
- Implementation of Alternative Source Term (AST) using RG 1.183 guidance
- FHA
  - Increase in fuel inventory
- MSLB & SGTR (Unit 2 only)
  - Change in mass release
- Other DBAs previously approved

DBA Radiological Consequences Analyses (continued)

- Analyses based on proposed EPU conditions
  - Power Level 2,918 MWt (100.6% of 2,900 MWt)
  - Amendments No 243 & 122 issued September 24, 2001 approved 1.4% Measurement Uncertainty Recapture Uprate
- NRC staff performed an on-site audit of the radiological analyses supporting both the SGR and EPU LARs

Other DBAs

Prior AST selective implementations per 10 CFR 50.67 performed for EPU conditions

- LOCA & CREA
  - Amendments No 257 & 139 issued September 10, 2003
- LRA, LACP, SLB (Both Units) MSLB & SGTR (Unit 1 only)
  - Amendment No 273 BVPS-1 Steam Generator Replacement issued February 9, 2006

Control Room Assumptions

- CR Emergency Ventilation System (CREVS) credited for MSLB
  - 600 cfm filtered intake (pressurization mode)
  - 30 cfm unfiltered inleakage
  - Tracer gas test supports inleakage assumptions
- Post release CR purge credit via CR Emergency Air Cooling System (CREACS) for MSLB, SGTR and for Unit 1 FHA
  - No CREACS purge credit for Unit 2 FHA

DBA Radiological Consequences Analyses Conclusions

- Licensee has adequately accounted for the effects of the proposed EPU
- All DBAs meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room
- The staff finds the proposed EPU acceptable with respect to the radiological consequences of DBAs

Reactor Vessel, Reactor Internal And Core Support Materials

James Medoff

Materials Engineer
Flaw Evaluation and Welding Branch
Division of Component Integrity
Office of Nuclear Reactor Regulation

Impact on PWSCC of Alloy 600 Materials

- The staff evaluated the EPU safety analysis report to assess its impact on the crack growth rates for cracks in Inconel materials that initiated by primary water stress corrosion cracking (PWSCC). These materials include Alloy 600 base metal materials and Alloy 82 or 182 (Alloy 82/182) filler metal materials.
- The piping at BVPS Unit 1 (BVPS-1) does not include any Alloy 600 base metal or Alloy 82/182 filler metal materials.
- The BVPS- 1 reactor vessel closure head (RVCH) does include Alloy 600 nozzles and Alloy 82/182 filler metal materials. FENOC is replacing the BVPS-1 RVCH during the current refueling outage. Inspections of the RVCH will follow the criteria for replacement RVCHs in the First Revised Order EA-03-009.

PWSCC of Alloy 600 (Continued)

- The Alloy 600 and Alloy 82/182 materials in the BVPS Unit 2 (BVPS-2) piping are managed by FENOC's Alloy 600 management program. This management program proposes augmented volumetric inspections of these piping components based on the susceptibility ranking for the materials.
- The Alloy 600 nozzles and Alloy 82/182 partial penetration welds in the BVPS-2 RVCH are categorized as components that are highly susceptible to PWSCC. FENOC performs augmented inservice inspections (AISI) of these components in accordance with the AISI criteria in the First Revised Order EA-03-009 for "high susceptible" RVCHs.

Impact of EPU on RV and RV Internal Integrity

- Impacts on Reactor vessel (RV) integrity include:
  - Surveillance capsule programs
  - RTpts value calculations for the pressurized thermal shock assessments
  - RTndt value calculations used in establishing pressure-temperature (P-T) limits for the reactor coolant pressure boundary
  - Upper shelf energy calculations for demonstrating acceptable margins against ductile tearing of the RV materials
- Impacts on the structural integrity of the RV internals and core support materials

Impact on RV Surveillance Capsule Program

- After considering the effects of the EPU, the licensee is required to pull a total of five capsules from BVPS-1 and four capsules from BVPS-2.

- The licensee has removed, tested, and reported the test results for four capsule from BVSP-1 and three capsules in accordance with 10 CFR Part 50, Appendix H and ASTM E185-82.

- Minor EPU-based adjustmenets of the proposed withdrawal times for fifth mandatory capsule at BVPS-1 and fourth mandatory capsule at BVPS-2 were determined to be in compliance with ASTM E185-82 and acceptable. These capsules will be removed at a time when the capsule fluences are between one to two times the peak EOL fluences for the RVs, which is inaccordance with E185-82.

Impact on PTS Assessments

- Calculation of RTpts values is required by 10 CFR 50.61. The rule establishes screening criteria of 270 °F for RV beltline axial weld and base-metal materials (i.e, plate or forging materials) and 300 °F for RV circumferential weld materials.
- Results for BVPS-1: Limited by lower shell plate B6903-1 (Plate Heat No. C6317-1):
  - Licensee EPU-based RTpts value: 256.6 °F at EOL
  - NRC EPU-based RTpts value: 259.5 °F at EOL
- Results for BVPS-1: Limited by intermediate shell plate B9004-1 (Plate Heat No. C0544-1).
  - Licensee EPU-updated RTpts value: 149.0 °F at EOL
  - NRC EPU-based RTpts value of 148.6 °F at EOL.
- Thus, the RVs will remain in compliance with 10 CFR 50.61 for the EPU.

Impact on Pressure-Temperature Limits

- Two related license amendments permitted FENOC to remove the BVPS-1/2 pressure-temperature (P-T) limits from the Technical Specification (TS) limiting conditions of operation and to make any necessary changes to them in accordance with the methodology in an NRC-approved pressure-temperature limits report (PTLR).
- The license amendments were granted on October 8, 2002, and again on July 15, 2003.
- For BVPS-1/2, any changes to the P-T limits and submittal of the corresponding PTLR to the NRC (for information) is administratively governed under the requirements TS 6.9.6.
- Any necessary EPU-based changes to the P-T limits for BVPS-1/2 will be handled in accordance with TS 6.9.6 and the licensee's PTLR process.

Impact on the Upper Shelf Energy Assessment

- Calculations of upper shelf energy (USE) values are required by 10 CFR Part 50, Appendix G. The rule establishes that USE values must be greater than or equal to 75 ft-lb for RV materials in the unirradiated condition and greater than 50 ft-lb thoughtout the licensed life of the plant .
- Results for BVPS-1: Limited by lower shell plate B6903-1 (Plate Heat No. C6317-1):
  - Licensee EPU-updated USE value: 56 ft-lb at EOL.
  - NRC EPU-updated USE value: 53.8 ft-lb at EOL.
- Results for BVPS-2: Limited by lower shell plate B9005-2 (Plate Heat No. C1408-1).
  - Licensee EPU-based USE value: 60 ft-lb at EOL
  - NRC EPU-based USE value of 59.4 ft-lb at EOL
- Thus, thus, the limiting RV beltline plate materials for BVPS-1 and BVPS-2 willl remain above 50 ft-lb and in compliance with 10 CFR Part 50, Appendix G under EPU-based conditions.

Reactor Internal and Core Support Materials

- The licensee is following the ASME Section XI inservice inspection (ISI) requirements.
- In addition, the licensee made commitments to participate in the industry's research program and will develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives.
- These commitments are consistent with Table Matrix-1 of Review Standard RS-001, Revision 0.

Conclusions

- The staff has concluded that the EPU will not significantly impact the safety margins for the following structural integrity assessments:
  - RV surveillance program
  - P-T limits for the reactor vessel
  - USE assessments for the RV
  - PTS assessment for the RV beltline materials
  - Structural integrity assessment of the RV internals
  - PWSCC of Alloy 600 and Alloy 82/182 components

BEAVER VALLEY POWER STATION

EXTENDED POWER UPRATE

SER SECTION 2.2

ENGINEERING MECHANICS BRANCH
(EEMB)

Kamal Manoly
Cheng-Ih (John) Wu
Thomas Scarbrough

- **Components Evaluated**
  - Reactor Vessel, Internals, Nozzles, Supports
  - Control Rod Drive Mechanisms
  - Steam Generator, Reactor Coolant Pump, Pressurizer and Supports
  - NSSS and BOP Piping Systems and Supports
  - Safety Related Valves (MOVs, AOVs, and SRVs)

- **Scope of Review**
  - Impact of EPU conditions due to changes in system pressure, temperature and flow rate.
  - Analytical methodology, loads, flow-induced vibration, calculated stresses and cumulative fatigue usage factors, acceptance criteria, ASME codes and addenda.
  - Functionality of valves and impact of EPU on GLs 89-10 and 96-05 for MOVs, and GL 95-07 for pressure locking and thermal binding.
  - EPU evaluation incorporating approved LBB for elimination of postulated primary loop pipe breaks.
  - Specific areas where staff requested additional information include MS and FW flow-induced vibration, analysis and results for BVPS Unit 1 main loop piping with SG, and CUF for vessel flange closure stubs.

Flow Induced Vibration

- MS and FW piping instrumented at critical locations and collected data are evaluated to ASME OM3.
- FIV on steam separator increases at EPU. FIV on steam separators is minimized due to its high stiffness and the low velocity of the passing flow.
- FIV on the U-bend tubing is within allowable limits (i.e., fluid-elastic instability ratio less than the limit of 1.0 and peak stresses less than material endurance limit)

- **Pump and Valve Modifications**
  - Charging/safety injection pumps modified to improve high head performance and flow rate.
  - Tolerance settings for Main Steam Safety Valves and Reactor Coolant Pressurizer Safety Valves adjusted.
  - New trim installed in the feedwater regulating valves (FRVs) in BVPS Unit 1 and FRVs replaced in BVPS Unit 2.
  - Fast-acting main feedwater isolation valves installed in BVPS Unit 1 similar to those in BVPS Unit 2.

- **Conclusion**

  - Stresses and CUFs in NSSS and BOP piping and components bounded by the original design basis analysis with the application of LBB.

  - The potential for flow-induced vibration not increased for the steam separators and the steam generator tubes for the EPU conditions.

  - MS and FW piping monitored to remain within allowable limits in ASME OM3 Code.

  - Safety-related valves and pumps will continue to meet NRC regulatory requirements during EPU operation at Beaver Valley.

Steam Generator Tube Integrity and Chemical Engineering Topics

Gregory Makar
Materials Engineer
Steam Generator Tube Integrity and
Chemical Engineering Branch
Division of Component Integrity
Office of Nuclear Reactor Regulation

Flow Accelerated Corrosion (FAC)

- The program scoping criteria are consistent with industry guidelines (temperature, moisture content, component alloy content, amount of usage).
- EPU conditions change the temperature, flow velocity, and moisture content for some components.
- These changes are expected to increase the corrosion rates of some components and decrease the corrosion rates in others.

Flow Accelerated Corrosion (FAC)

- CHECWORKS computer models are being updated prior to implementing the EPU.
- The updated models are used in determining future inspection and repair/replacement plans.
- At EPU conditions the FAC program remains consistent with industry guidelines.

Steam Generator Tube Inservice Inspection

- Unit 1 has replacement steam generators with thermally treated Alloy 690 tubes and stainless steel tube support components (2006).
- Operating temperature will remain within the range found at other plants with Alloy 690 steam generator tubes.
- For Unit 1, the inspection program will continue to manage degradation effectively at EPU conditions.

Steam Generator Tube Inservice Inspection

- Unit 2 has original steam generators with mill annealed Alloy 600 tubes and both carbon steel and Alloy 600 tube support components.
- Increases in temperature, feedwater flow rate, and sludge accumulation could increase degradation rates.
- EPU conditions are not expected to introduce new forms of degradation.
- For Unit 2, the inspection program will continue to manage degradation effectively at EPU conditions.

Steam Generator Blowdown System (SGBS)

- Blowdown flow rates will not be affected by the change to EPU conditions, although blowdown flow-control valves may have to be repositioned.
- The ability of the SGBS to remove impurities from the secondary coolant will not be reduced at EPU conditions.
- Corrosion rates of SGBS components will continue to be monitored under the Flow Accelerated Corrosion Program.

Chemical and Volume Control System

- EPU operating conditions for heat exchangers are bounded by design values.
- Boration requirements at EPU conditions remain within system capabilities.
- Letdown flow rates, charging flow rates, and N-16 delay times will not be significantly affected by the EPU.

Protective Coatings (Paints) Organic Materials

- Original coating application was in accordance with ANSI N101.2 for both Unit 1 and Unit 2.
- Normal operating and design basis accident conditions in containment are bounded by coating system qualification tests for both Unit 1 and Unit 2 (temperature, pressure, radiation dose, chemical concentration)
- Coating failures are identified by inspection and evaluated by the Corrective Action Program.

Balance-Of-Plant (BOP) Systems

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Balance of Plant Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

Scope of Review for BOP Systems

- Review per RS-001, Matrix 5
  - Internal Hazards
  - Fission Product Control
  - Component Cooling and Decay Heat Removal

Scope of Review for BOP Systems

- Review per RS-001, Matrix 5 (continued)
  - Balance-of-Plant Systems
  - Waste Management Systems
  - Emergency Diesel Fuel Oil Storage & Light Loads
- BOP Testing Considerations

Scope of Review for BOP Systems

- Spent Fuel Pool Cooling
- Service Water System/Ultimate Heat Sink
- Auxiliary Feedwater System
- Condensate and Feedwater System

Modifications to BOP Mechnical Systems

- Replacement of High Pressure (HP) all-reaction turbines

- Addition of auxiliary feedwater flow limiting venturies for BVPS-1.

High Pressure Turbine Modification

- In both units the high pressure turbine is being replaced by an all reaction turbine.
- Unit 1 - modification completed - maximum overspeed calculated to be 118% which is below the acceptance criteria of 120%.
- Unit 2 - modification will be completed prior to operation at EPU and the licensee has comitted to perform appropiate turbine overspeed analysis to ensure overspeed protection is acceptable.

Auxiliary Feedwater System Modifications

- Cavitating veturies were installed in Auxiliary Feedwater System of BVPS-1.
- At EPU the number auxiliary FW pumps credited for the FWLB and LONFW events for BVPS-1 is now two.
- Unit 2 licensing basis already credits two AFW pumps for theses FW events and is not changed by EPU.
- Total required AFW flow for FWLB and LONF events for operation of uprated BVPS-1 will be well within the capacity of any two AFW pumps.
- Technical Specifications requires 3 AFW pumps be operable.

BOP Systems - Summary

- The staff finds the proposed EPU to be acceptable with respect to BOP area, based on:
  - the evaluation that was performed
  - the commitments that were made, and
  - testing that will be completed

Beaver Valley Power Station EPU
NRC Staff Review of Risk Evaluation

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Senior Reliability & Risk Analyst
PRA Licensing Branch A
Division of Risk Assessment
Office of Nuclear Reactor Regulation

Overview

- Licensee assessed potential risk impacts of the proposed EPU
- The proposed EPU does not create "special circumstances" that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately assessed by the licensee and are acceptable

EPU Risk Evaluations

- EPU submittals are not risk-informed
- Per RS-001, Rev. 0, "Review Standard for Extended Power Uprates," Matrix 13, "Risk Evaluation," licensees perform risk evaluations to:
  - Demonstrate that risks are acceptable, and
  - Determine if "special circumstances" exist (as defined in SRP 19, Appendix D)
- BVPS EPU is for an 8% increase

Scope of the Risk Evaluation

- Full-power PRA model
  - Internal events, including internal flooding
  - Seismic
  - Internal Fires
  - CDF and LERF
- Qualitative approach for other risk
  - High winds, external floods, other external events – screening per NUREG-1407
  - Shutdown risk – questions in SRP Chapter 19

PRA Quality

- Owners Group Peer Review July, 2002
  - 5 A level and 19 B level Facts & Observations (F&Os)
  - Resolution of F&Os incorporated into PRA model
- SDP Phase 2 model benchmarked 09/24/03 (both units)
- Seismic and fire PRA models
  - Reviewed internally by utility personnel and by IPEEE contractors
  - NRC SER found the results to be reasonable and capable of identifying the most likely severe accidents and vulnerabilities
  - Seismic and fire PRA models are integrated with the internal events PRA models
- <u>NRC staff finds PRA used in support of the EPU is of sufficient quality, scope, and level of detail to analyze the risks stemming from the EPU</u>

PRA Quality (cont'd)

- Onsite audit by NRR 10/18-19/2005
- Purposes of Audit:
  - Understand risk impact of EPU taken by itself
  - Check quality of PRA and risk assessment
  - Understand/clarify selected RAI responses
- Key Findings
  - Need to estimate risk from EPU alone, without model enhancements or unrelated changes
  - Need to explain several MAAP results
- Results
  - Good PRA configuration control process
  - Licensee corrected one MAAP model error and updated results
  - Licensee submitted risk assessment representing just EPU risk

EPU Impact on Initiating Events and Equipment Reliability

- EPU does not result in new initiating events and is not expected to increase the frequency of any initiating event
  - Equipment operating ranges and limits are maintained
  - Plant modifications will be implemented where necessary
- EPU will not adversely effect system functions important to risk
  - Plant modifications made to maintain or improve the performance of certain equipment
  - Plant systems and equipment will continue to be operated within design constraints
  - Component failure rates and equipment unavailability will not significantly change with the implementation of the EPU

EPU Impact on Accident Sequences & Success Criteria

- General accident progression in PRA not impacted by EPU
- For the most part, success criteria remains the same
- Station Blackout (SBO) impacted slightly -shorter time to core damage impacts time to recovery offsite power
- ATWS success criteria impacted
  - Cavitating venturis in AFW precludes ability to deliver full flow from all 3 AFW pumps to the steam generators
  - BVPS PRA models conservatively do not credit full AFW flow, so no calculated increase in ATWS risk from this source
  - Actual increase in ATWS risk would be very small, since ATWS accounts for less than 1% of total CDF for each unit
- Design basis loss of feedwater transient success criteria impacted, but best estimate criteria unchanged by EPU
- Negligible impact on containment accident pressure credit for ECCS NPSH (next slide)

Containment Accident Pressure for ECCS NPSH

- For Unit 1, pre-EPU licensing basis allows consideration of containment accident pressure in calculation of NPSH
- Unit 2 does not credit containment accident pressure due to physical design differences
- Only the Unit 1inside and outside recirculation spray pumps credit containment accident pressure
- Insignificant change in risk resulting from EPU
  - Accident pressure required for short duration (10-20 minutes)
  - Vendor tested a pump hydraulically identical to BVPS recirculation spray pumps and demonstrated the pumps are capable of stable operation at conditions where NPSH is reduced below the standard requirement
  - The difference in duration pre-EPU compared to post-EPU case is on the order of a minute (based on a representative calculation)

EPU Impact on Human Reliability

- EPU reduces time available for the operators to act, which may increase human error probability
- Change in HRA due to EPU not assessed directly (licensee performed sensitivity analysis) because:
  - Pre-EPU timing based mostly on hand calculations; post-EPU used MAAP analyses
  - HRA method cannot translate small changes in time available into meaningful changes in human error probability
- EPU risk due to operator action timing assessed by:
  - Quantifying post-EPU CDF and LERF using HRA timing from MAAP
  - Validating that important operator actions with short time available are not precluded at EPU timing
- NRC staff conclusion focused on post-EPU CDF and LERF and on whether adequate protection of public health and safety will be maintained

EPU Impact on Human Reliability (cont'd)

- Important operator actions with short time available
  - Depressurize the RCS
  - Implement feed and bleed cooling
  - Manually start auxiliary river water pumps (unit 1)
  - Manually start AFW on failed SSPS (unit 2)
- Licensee validated that these can be performed in the EPU time available and used MAAP to determine timing
- Depressurization and feed & bleed actions
  - Proceduralized, routinely practiced on the simulator, performed in control room (model includes local actions for depressurization in some scenarios)
  - Take a relatively short time to perform (2 -10 minutes)
  - Occur in response to symptom based procedures (EOPs and FRPs)
  - A reduction in time available would not be expected to have a significant impact on human error probability unless the time became so short the operator did not reach the procedure step
- The manual actions to start pumps are simple actions performed from the control room

EPU Impact on External Events Risk

- Fire
  - EPU not expected to result in new internal fire initiators, increase fire initiating event frequency, or result in new internal fire core damage or LERF scenarios
  - EPU has very small impact fire risk
- Seismic
  - EPU not expected to result in changes in SSCs' response to a seismic initiator or result in new seismic core damage or LERF scenarios
  - EPU has very small impact seismic risk
- Other External Events
  - EPU implementation will not affect the high winds, floods, and other external events analysis
  - The IPEEE evaluation remains applicable at EPU conditions

EPU Impact on at-Power Risk

Estimated Risk: EPU Implementation*		
(Per reactor year)	Unit 1	Unit 2
CDF post EPU	2E-5	3E-5
CDF Increase**	3E-7	4E-7
LERF post EPU	5E-7	1E-6
LERF Increase**	6E-8	5E-8

* Total - Internal events, fire and seismic
** HRA sensitivity + other EPU changes

EPU Impact on Shutdown Risk

- Shutdown initiating events are not impacted by EPU
- Impact of increased decay heat is not significant
  - Small decrease in the time available for operator actions
  - Adequate defense-in-depth minimizes impact of decreased response time
- Licensee will continue to control shutdown risk using plant procedure
  - Requires monitoring of the plant defense-in-depth features available during these operating modes
  - Provides guidance for evaluating the adequacy of protective measures, and specifies actions to be taken to ensure that there are adequate protective measures in place.
  - Requires development of a Pre-Outage Shutdown Safety Review of key shutdown safety functions.

Conclusion

- Licensee assessed potential risk impacts of the proposed EPU
- The proposed EPU does not create "special circumstances" that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately assessed by the licensee and are acceptable

Human Performance

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Human Factors Engineering Evaluation

- Areas of Review
  - Programs, procedures, training, and human system interface design features that are related to operator performance
- Purpose
  - Assure that the proposed Extended Power Uprate (EPU) does not adversely affect operator performance

Regulatory Criteria

- RS-001, "Review Standard for Extended Power Uprates Draft Review Standard for Power Uprates," Matrix 11
- 10 CFR 50.120
- 10 CFR Part 55
- Generic Letter 82-33
- Standard Review Plan Chapter 18.0, "Human Factors Engineering"

RS-001, Matrix 11, Standard Questions Related to Affects of EPU

- Emergency and Abnormal Operating Procedures
- Operator Actions Sensitive to Power Uprate
- Control Room Alarms, Controls, Displays
- The Safety Parameter Display System (SPDS)
- Operator Training Program and Control Room Simulator

Emergency and Abnormal Operating Procedures

- Changes include slight modifications for parameter thresholds and graphs which depend on power and decay heat levels and changes in setpoints
- Elimination or revision of procedures to reflect the elimination of technical specification requirements associated with boron injection tank (BIT)

Operator Actions Sensitive to Power Uprate

- EOP operator actions used in analysis
  - New operator action: control room purge after SGTR
  - Change to operator actions: Control Room purge after MSLB is now for 30 minutes at 16,200 cfm instead of within 8 hours of termination of environmental release
- Several operator action times affected in both units
  - Time reductions for some operator actions due to increased decay heat

Operator Actions Sensitive to Power Uprate

- Decreased Operator Actions Times:
  - Unit-1
    - Times validated for revised EOPs & confirmed on simulator and by step by step walk-through in plant
  - Unit-2
    - Revisions to EOPs not completed at this time
    - Licensee committed to validating operator action times obtained through talk-through process as part of procedural change process
- Staff determined acceptable based on Unit-1 validations and provided licensee validates performance in Unit-2 simulator prior to power uprate

Operator Actions Sensitive to Power Uprate

Summary of Restrictive Operator Action Times

Operator Action	Time Available/ Times used in EPU analysis	Action Performance Time	Time Used in current EPU analysis
Unit 1			
terminate high head safety injection flow to RCS	within 10 Minutes of the start of the event	9.7 minutes	No time for this action used in the current analysis
Unit 2			
isolate auxiliary feedwater flow to the ruptured SG	within 5.5 minutes after reactor trip	5.0 minutes	within 9.1 minutes after reactor trip
initiate cooldown from the intact SGs via the main steam system after MSIV closure	within 2.0 minutes after the MSIV is closed for inside the main control room	2.0 minutes	No time for this action used in the current analysis
	within 7.0 minutes after the MSIV is closed for outside the main control room	6.0 minutes	within 9.0 minutes after the MSIV is closed for outside the control room

Control Room Alarms, Controls, Displays

- Licensee provided a summary of limits, setpoints, and alarms affected including
  - Rx Trip setpoints -overprotection
  - Pressurizer Water Level Program
  - Accumulator water lever and pressure setpoints
  - Primary Plant Demineralized Water Tank (unit 1 only)
  - Replacement SG revisions to associated water level setpoints, alarms, EOPs, and the SMAGs (unit 1 only)
  - Steam Dump; Turbine 1st stage pressure alarm
  - RWST setpoints

Control Room Alarms, Controls, Displays

- No controls, displays, or alarms will be upgraded from analog to digital except the SI accumulator pressure indication display which will be upgraded for improved accuracy
- Re-normalized
  - Interfaces for control room controls, displays, & alarms will be such that 100% indications of rated thermal power (RTP) will remain at 100% RTP
  - No changes in operator actions for normalized protection, control, displays, and alarms

Safety Parameter Display System (SPDS)

- Instrument spans & setpoints changing in both units
- Replacement steam generators Unit-1 impact SPDS
  - Increased narrow range steam generator water level instrument span.
  - Display system will be re-calibrated such that the process limits match the existing patterns
- Plant Engineering Change Process (ECP) will be followed to make changes to SPDS
  - Includes operations, training, and the simulator groups when determining impacts on the changes and determining if additional training is necessary

Operator Training Program and Control Room Simulator

- ECP requires training department to perform an evaluation per the Systematic Approach to Training for all affected plant modifications, procedural changes, and operator action times
- Both units' simulators will be bench-marked with the best estimate engineering models for the 10 ANSI/ANS-3.5 Appendix B transients
  - Simulators will initially compared to the predicted values at 100% steady state; this will be followed by a final comparison to actual plant values at 100% power

Operator Training Program and Control Room Simulator

- Training will cover plant modifications, procedure changes, & changes to parameters, setpoints, scales, system
- Training & simulator changes will be completed prior to EPU implementation

Conclusions

- The licensee has:
  - Addressed the effects of the proposed EPU on available time for operator actions
  - Taken or has committed to take appropriate actions to assure that the EPU does not adversely affect operator performance
- The licensee will continue to meet applicable NRC requirements related to human performance
- The NRC finds the licensee's proposed EPU acceptable with respect to human factors

Beaver Valley Power Ascension and Test Program

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Office of Nuclear Reactor Regulation

Beaver Valley EPU Test Program

- Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," provides guidance for testing programs based on Regulatory Guide (RG) 1.68 and plant specific initial test program.
- EPU test program should include testing sufficient to demonstrate structures, systems, and components (SSCs) will perform satisfactorily at the requested power level.
- Staff guidance considers original power ascension test program and EPU related plant modifications.
- Staff guidance acknowledges that licensees may propose alternative approaches to testing with adequate justification.

Beaver Valley EPU Test Program

- Staff basis for requiring performance of LTT should consider Regulatory Guide 1.68 testing "Objectives"
  - Operator training and familiarization,
  - Confirmation of design and installation of equipment,
  - Bench marking of analyses codes and models, and
  - Confirmation of the adequacy of emergency and operating procedures.

Beaver Valley EPU Test Program

- Beaver Valley will perform additional start-up tests for Unit 1 which were not originally part of the initial start-up test program.
  - Maintain consistency with Unit 2 (these tests were initially applicable),
  - Examples include: secondary system vibration frequency and amplitude tests, secondary system expansion and restraint tests, primary sampling system tests, and Turbine plant system tests.
- Beaver Valley will perform a series of post modification tests for plant design changes associated with the power uprate:
  - Replacement of plant instrumentation and controls (e.g., Prz. Level control, Main steam, main feedwater control systems)
  - Modification to HP Turbine, Charging pump internals

Beaver Valley EPU Test Program

- Beaver Valley application does not require the performance of LTT (e.g., MSIV closure, T-G load rejection)
- Accepted justifications for not performing LTT for previous power uprate applications were applicable to the Beaver Valley EPU application.
  - The licensee's test program will monitor important plant parameters during EPU power ascension.
  - TS surveillance and post-mod testing will confirm the performance capability of the modified components.
  - Operating history and experience at other similar 3-loop LWRs at similar power levels (North Anna, Summer, Harris).
  - LTT is not needed for Code analyses bench marking.

Beaver Valley EPU Test Program

Conclusion

- SRP 14.2.1 allows for justification for not performing EPU power ascension tests.
- Fifteen domestic LWRs have implemented staff approved EPUs (up to 120% OLTP) without performance of LTT.
- Beaver Valley will implement a thorough test plan consistent with the initial test program and plant modifications based on the uprated conditions.
- The staff concludes that the proposed test program provides adequate assurance that the plant will operate in accordance with the design criteria and that SSCs affected by the proposed EPU will perform satisfactorily in service.

LBLOCA

CONSERVATISMS IN OXIDATION CALCULATION

- REFLOOD TIME PERIOD EXTENDED
- CONSERVATIVE W COBRA/TRAC TRANSIENT IS CHOSEN
- CONSERVATIVE ROD POWER CENSUS
- CONSERVATIVE ESTIMATES OF OXIDATION FRACTIONS

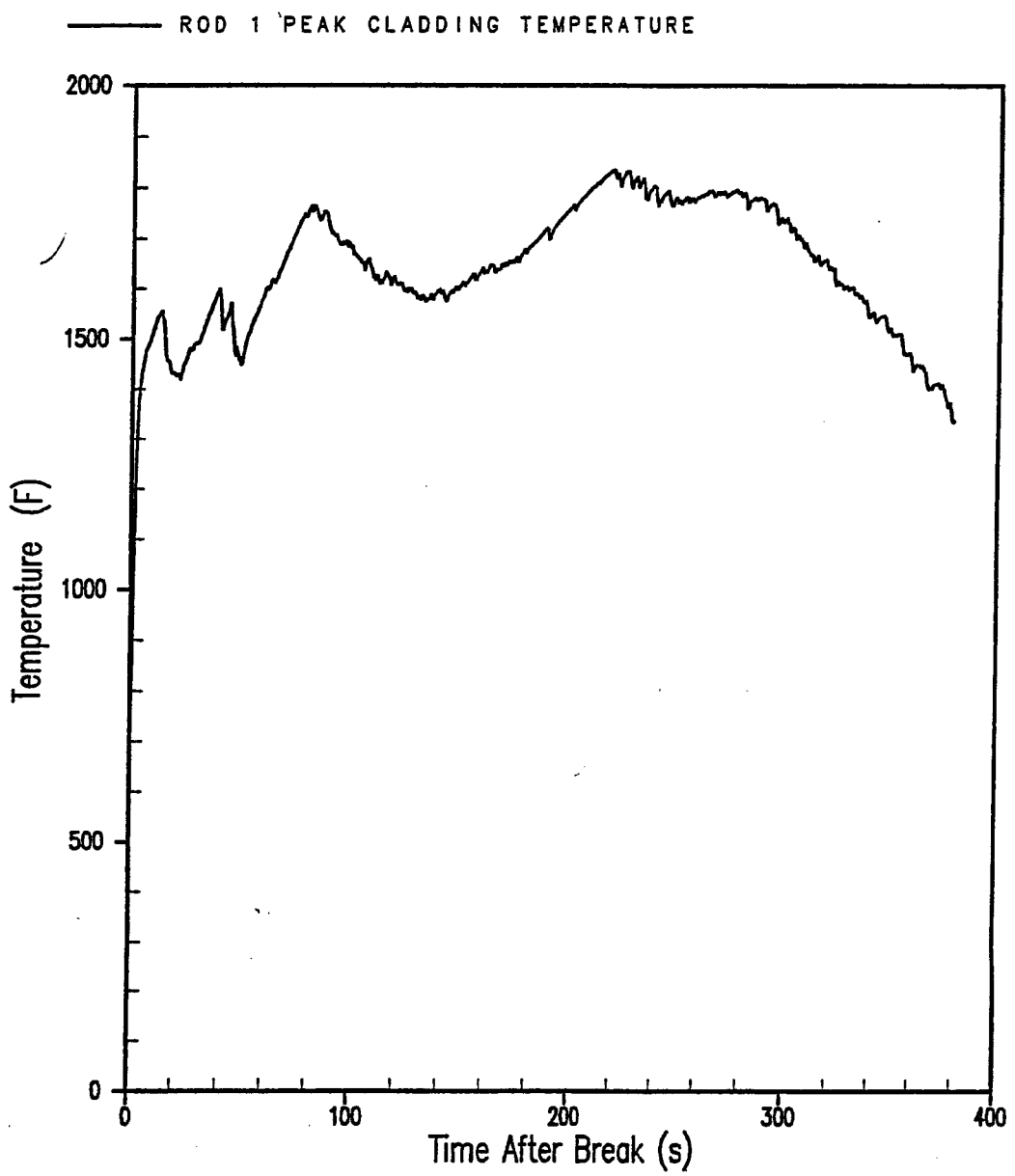


Figure 8.4-2 Peak Cladding Temperature for Reference Split Transient

CONTROL OF BORIC ACID

- LARGE BREAKS

  - RE-ALIGN HPSI TO SIMULTANEOUS HOT AND COLD SIDE INJECTION

- SMALL BREAKS

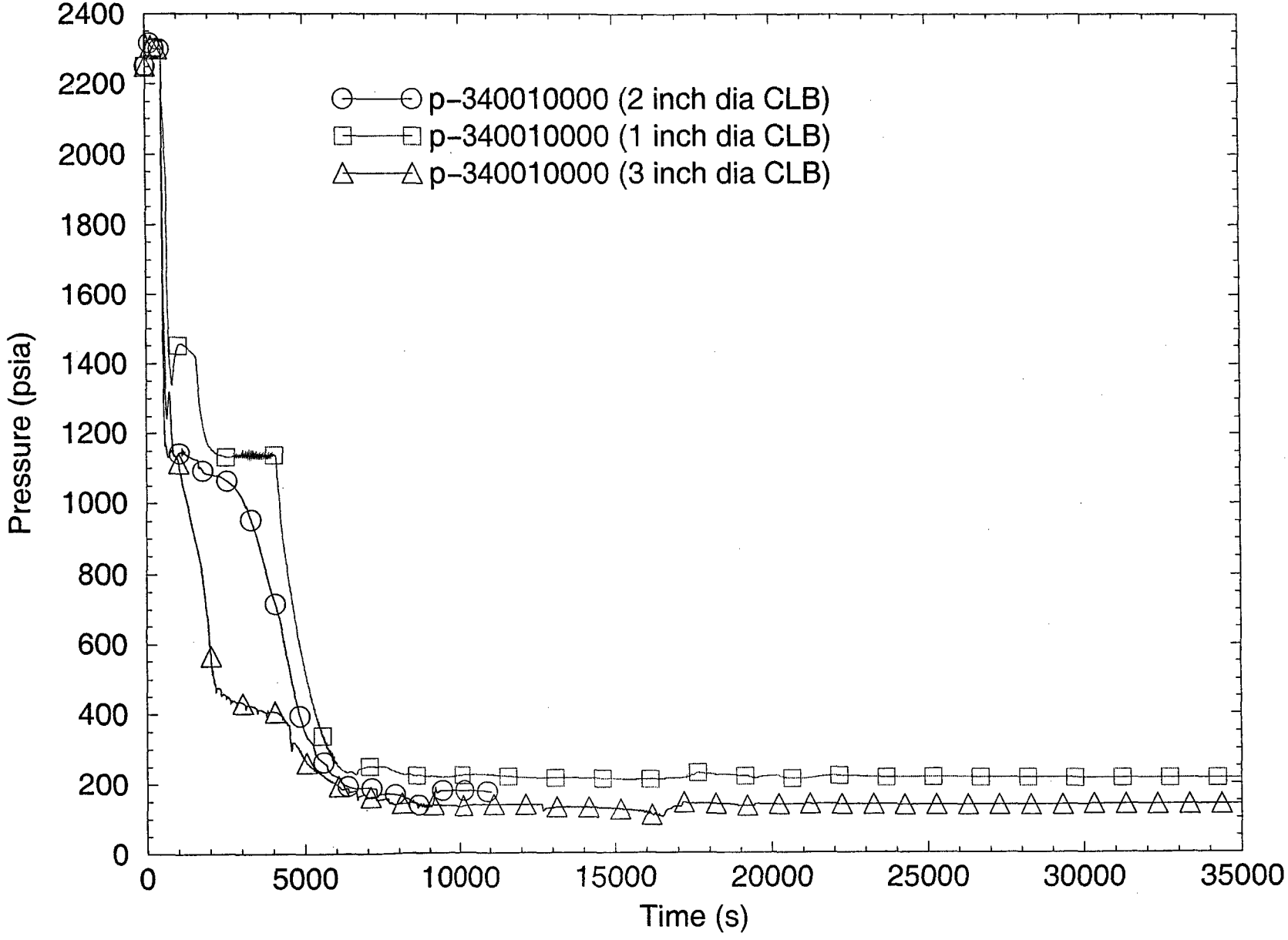
  - COOLDOWN RCS TO LOW PRESSURE FOR CORE FLUSH BY HPSI

  OR

  - REFILL RCS WITH ECC (RE-ESTABLISH SINGLE PHASE NAT. CIRC.)

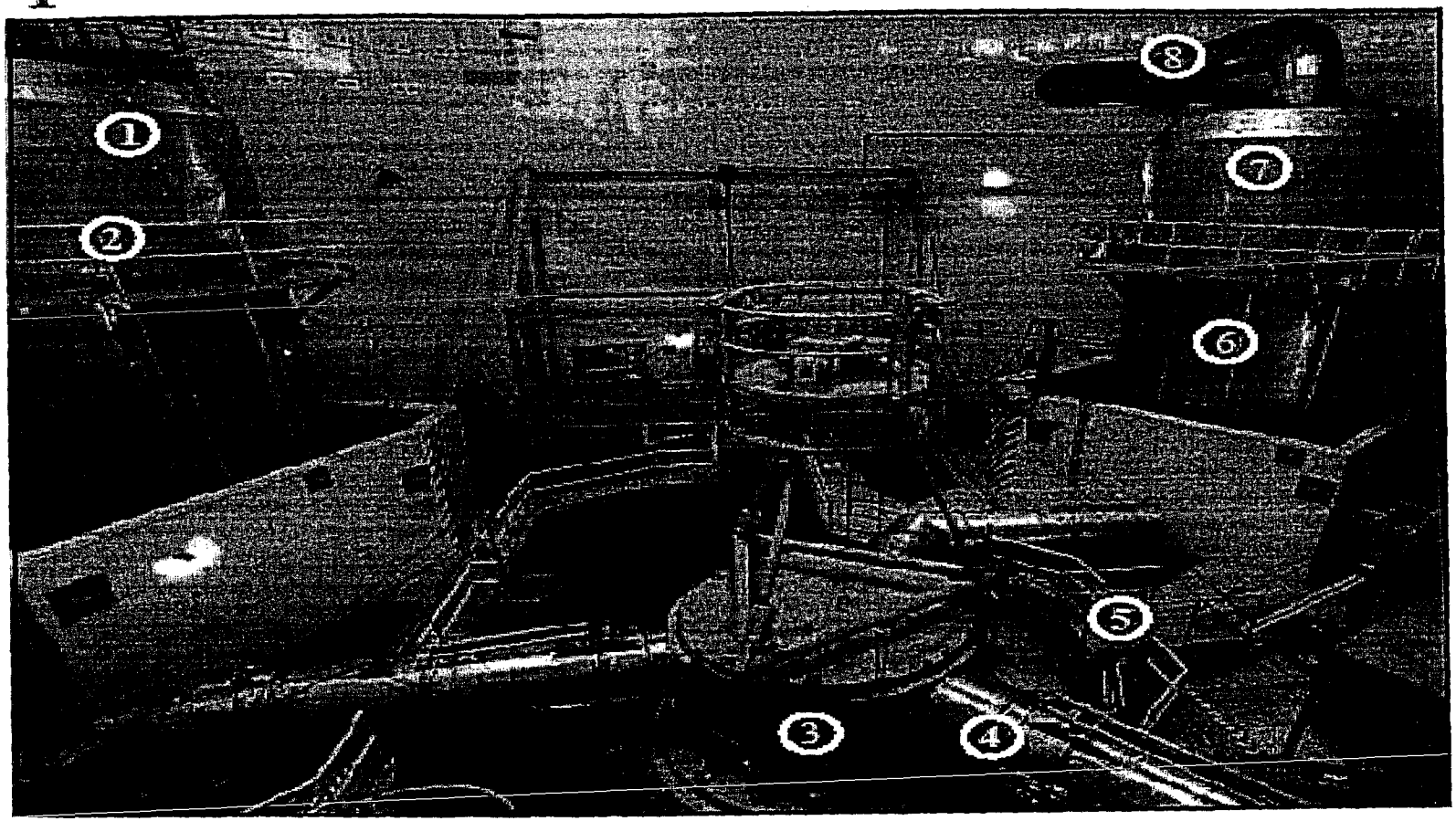
RCS Pressure vs Time

Beaver Valley EPU, SBLOCA



WHAT'S NEW *inside BV Unit 1 Containment*

Take a look below at the improvements made inside Unit 1 Containment during Beaver Valley's 1R17 outage.



1) Three brand new 368-ton steam generators were installed. Shown here is the top portion of Steam Generator 'B.'
2) New catwalks on the steam generators will eliminate the need to build scaffolding, saving time and dose.
3) A new, simplified Reactor Vessel Head will save 12 polar crane lifts per outage in the future.
4) A new configuration for the Control Rod Drive Mechanism ventilation was installed.
5) The Cable Bridge will allow easier access to the head and will simplify the process of disconnecting the Control Rod Drive Mechanisms and Rod Position Indicators in future refueling outages.
6) New mirror insulation was installed on all three Steam Generators and the Reactor Vessel Head. The insulation will help keep heat inside the steam generators and debris out of the containment sump.
7) Steam Generator 'A.' Steam Generator 'C' is not shown.
8) Close to 1.4 miles of welds on the Reactor Coolant System, Main Steam System, Feedwater Lines and instrument tubing were completed.

EPU Technical Specification Changes:

- Increasing the Maximum Power Level specified in each unit's license
- Revising the value of Rated Thermal Power (RTP) and adding definition to LRM
- Revising fuel assembly specific Departure from Nucleate Boiling Ratios (DNBR) and correlations
- Raising the maximum temperature of the refueling water storage tank
- Raising the positive tolerance setting for the pressurizer safety valves
- Revising the primary plant demineralized water storage tank volume requirement
- Adding WCAP-14565, VIPRE, and WCAP 15025, WRB-2M, to the list of approved NRC methodologies in Technical Specification 6.9.5

EPU Technical Specification Changes (Cont.):

- Deleting the Power Range, Neutron Flux High Negative Rate trip
- Increasing the operating band for accumulator water volume and nitrogen pressure (Unit 2 only)
- Revising the Steam Generator Technical Specification tube sleeve reference and TIG welded Steam Generator sleeve repair limit (Unit 2 only)
- Revising the specific activity of the primary and secondary coolant systems (Unit 1 only)
- Revising the required charging pump discharge pressure for reactor coolant pump seal injection flow (Unit 2 only)
- Raising the positive tolerance setting for the main steam safety valves (all but the lowest MSSV)
- Changing the allowable power limits associated with inoperable main steam safety valves

Nominal Operating Parameters (BVPS-1)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	577.9	576.2	+1.7F
Tcold (F)	544.6	545.1	-0.5F
Delta T (F)	66.6	62.2	+4.4F
Thot (F)	611.2	607.3	+3.9F
Coolant Mass Flow (total lb/hr)	1.11E+08	1.11E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	440	434.3	+5.7F
Stm Out (psia)	805	825	-20 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

Nominal Operating Parameters (BVPS-2)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	574.2	576.2	-2F
Tcold (F)	538.9	543.4	-4.5F
Delta T (F)	70.6	65.6	+5F
Thot (F)	609.5	609	+0.5F
Coolant Mass Flow (total lb/hr)	1.05E+08	1.05E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	437	434	+3F
Stm Out (psia)	774	821	-47 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

BVPS-1 OTΔT and OPΔT Equations

OTΔT Equation

$$\Delta T\cdot\left[\frac{1}{\left(1+\tau_4\cdot S\right)}\right] \le \Delta T_o\cdot\left[K_1 - K_2\cdot\left[\frac{\left(1+\tau_1\cdot S\right)}{\left(1+\tau_2\cdot S\right)}\right]\cdot\left[T\cdot\left[\frac{1}{\left(1+\tau_5\cdot S\right)}\right] - T^1\right] + K_3\cdot\left(P - P^1\right) - f\cdot\left(\Delta I\right)\right]$$

OPΔT Equation

$$\Delta T\cdot\left(\frac{1}{1+\tau 4\cdot S}\right) \le \Delta T_o\left[K_4 - K_5\cdot\left(\frac{\tau_3\cdot S}{1+\tau_3\cdot S}\right)\cdot\left(\frac{1}{1+\tau_5\cdot S}\right)\cdot T - K_6\cdot\left[T\cdot\left(\frac{1}{1+\tau_5\cdot S}\right) - T^{11}\right]\right]$$

- For BVPS-1, the K1, primary term used in the Overtemperature ΔT function to limit reactor power is reduced from 1.259 to 1.242, a reduction of 1.7% RTP given steady state conditions.

- For BVPS-2, the K1, primary term used in the Overtemperature ΔT function to limit reactor power is reduced from 1.311 to 1.239, a reduction of 7.2% RTP given steady state conditions.

- For Unit 1, the K4, primary term used in the Overpower ΔT function to limit reactor power is reduced from 1.0916 to 1.085, a reduction of 0.6% RTP given steady state conditions.

- For Unit 2, the K4, primary term used in the Overpower ΔT function to limit reactor power is maintained at 1.094

- The reduction in steady-state operating margin as a result of the "tuning" of this reactor trip function does not introduce possibility of spurious runback or plant trips due to the incorporation of lag modules that effectively filter out small input signal variations.

Pressurizer Level Control	22%= 547°F 54% @ full power Linear ramp Full power Tavg @ 576.2°F	22%= 547°F Variable @ full power Linear ramp Full power Tavg @ 566.2-580°F	No control changes No change of reference level at no-load temp. Tavg @ 566.2°F , 44% Tavg @ 576.2°F, 55-56% Tavg @ 580°F, 60% Revised level program will be implemented in 1R17 & 2R12
Steam Dump Control, Load Rejection Controller, Deadband	2°F	3°F	Changed to support maintaining P9 setpoint at EPU conditions
Steam Dump Control, Reactor Trip Controller, Trip Open Setpoints	First Bank 11.1°F Second Bank 20.0°F	First Bank 15.6°F / 9.1°F Second Bank 33.0°F/19.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, Load Rejection Controller, Trip Open Setpoints	First Bank 9.5°F Second Bank 16.7°F Third Bank 25.7°F Fourth Bank 33°F	First Bank 8.8°F / 5.8°F Second Bank 15.3°F/9.0°F Third Bank 23.4°F/13.0°F Fourth Bank 30.0°F/16.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, Reactor Trip Controller, Trip Open Setpoints	First Bank 11.1°F Second Bank 20.0°F	First Bank 15.6°F / 9.1°F Second Bank 33.0°F/19.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, C-7B Setpoint	50%	35%	Changed to support maintaining P9 setpoint at EPU conditions
SG Level Control (Nominal setpoint)	44% NR Level	44% NR Level (BVPS-2) 65% NR Level (BVPS-1)	Nominal Level changing due to RSG (BVPS-1 only). Will be implemented in 1R17

BELOCA Methodology

The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

- Other inputs are treated statistically as follows
- Nominal values used to establish a limiting reference transient
- Sensitivities are developed based on specified operating range
- 95/95 PCT is established using monte-carlo sampling over desired operating range
- Uncertainties are grouped into three categories:
  - Model parameter bias and uncertainty
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to develop a distribution of PCTs

$$PCT_i = PCT_{REF} + \Delta PCT_{I,MOD} + \Delta PCT_{i,PD} + \Delta PCT_{i,IC} + \text{Superposition Correction}$$

BELOCA Methodology

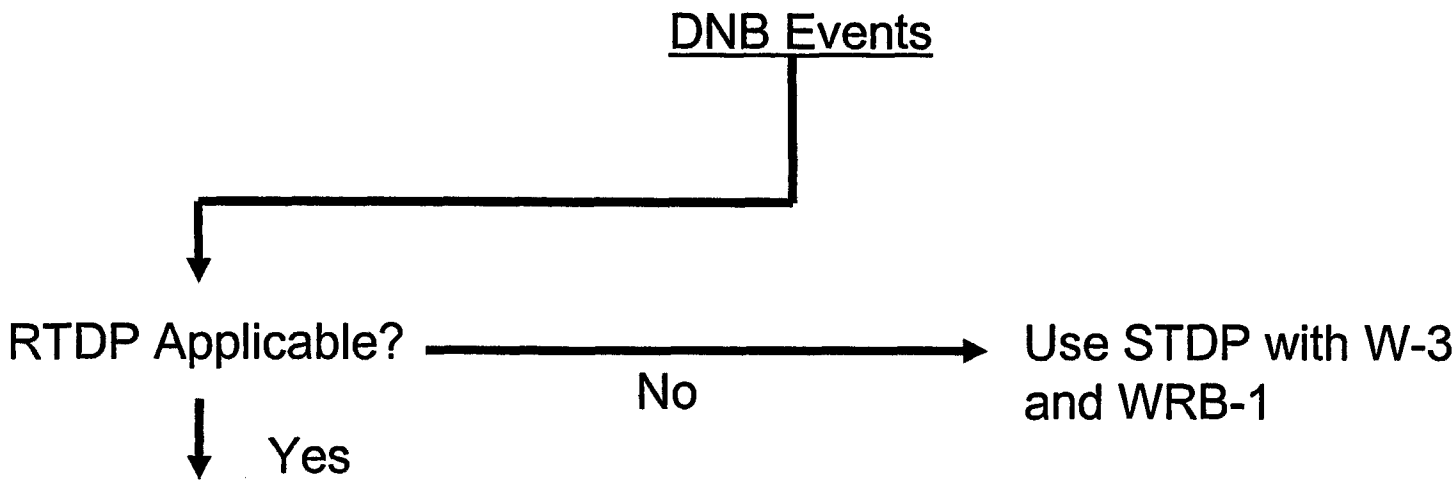
The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

- Other inputs are treated statistically as follows
- Nominal values used to establish a reference transient
- Sensitivities are developed based on specified operating range
- 95/95 PCT is established using monte-carlo sampling over desired operating range
- Uncertainties are grouped into three categories:
  - Model parameter bias and uncertainty
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to establish 95th percentile PCT

$$PCT_{95} = PCT_{REF} + \Delta PCT_{MOD} + \Delta PCT_{PD} + \Delta PCT_{IC} + \text{Superposition Correction}$$



Use WRB-2M where applicable

Not applicable for:

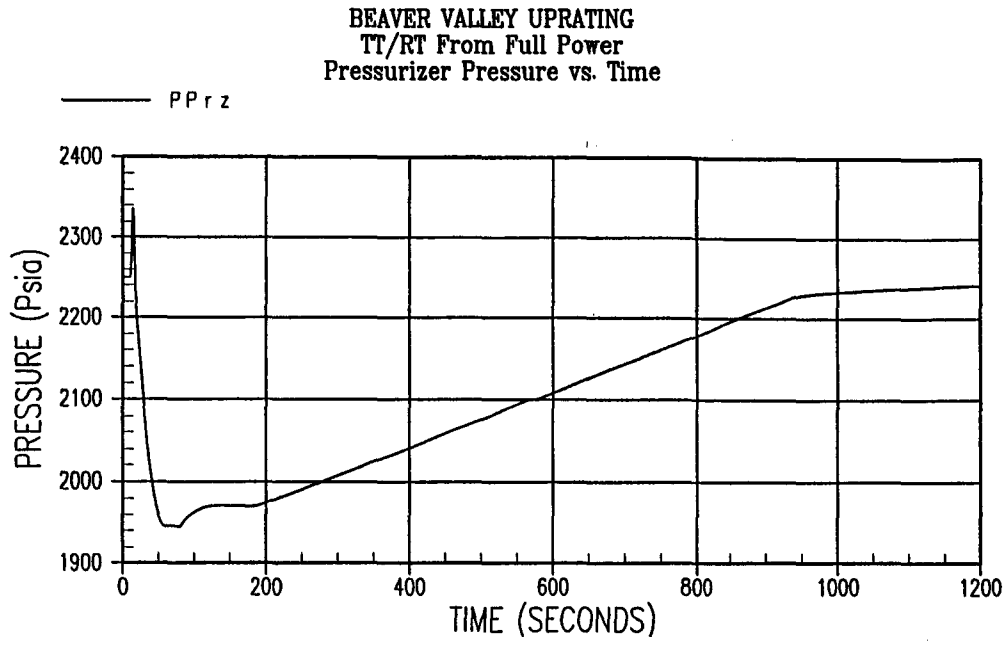
1) Events at 0% power

2) DNBR analysis below first mixing vane grid

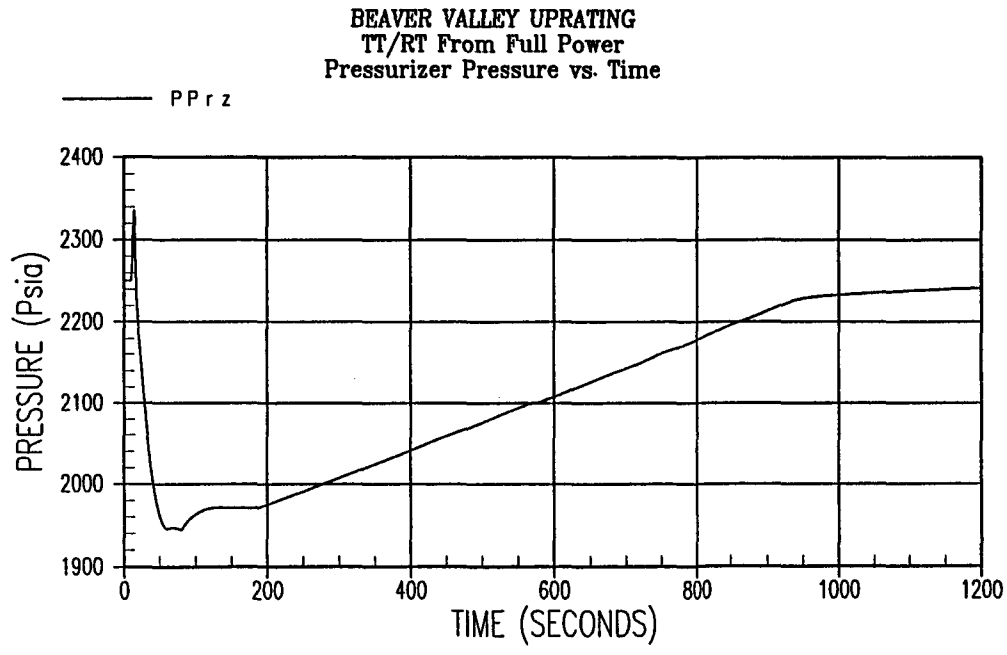
   (W-3 used for this analysis)

3) For analysis where fluid conditions are outside the approved quality or pressure range for WRB-2m

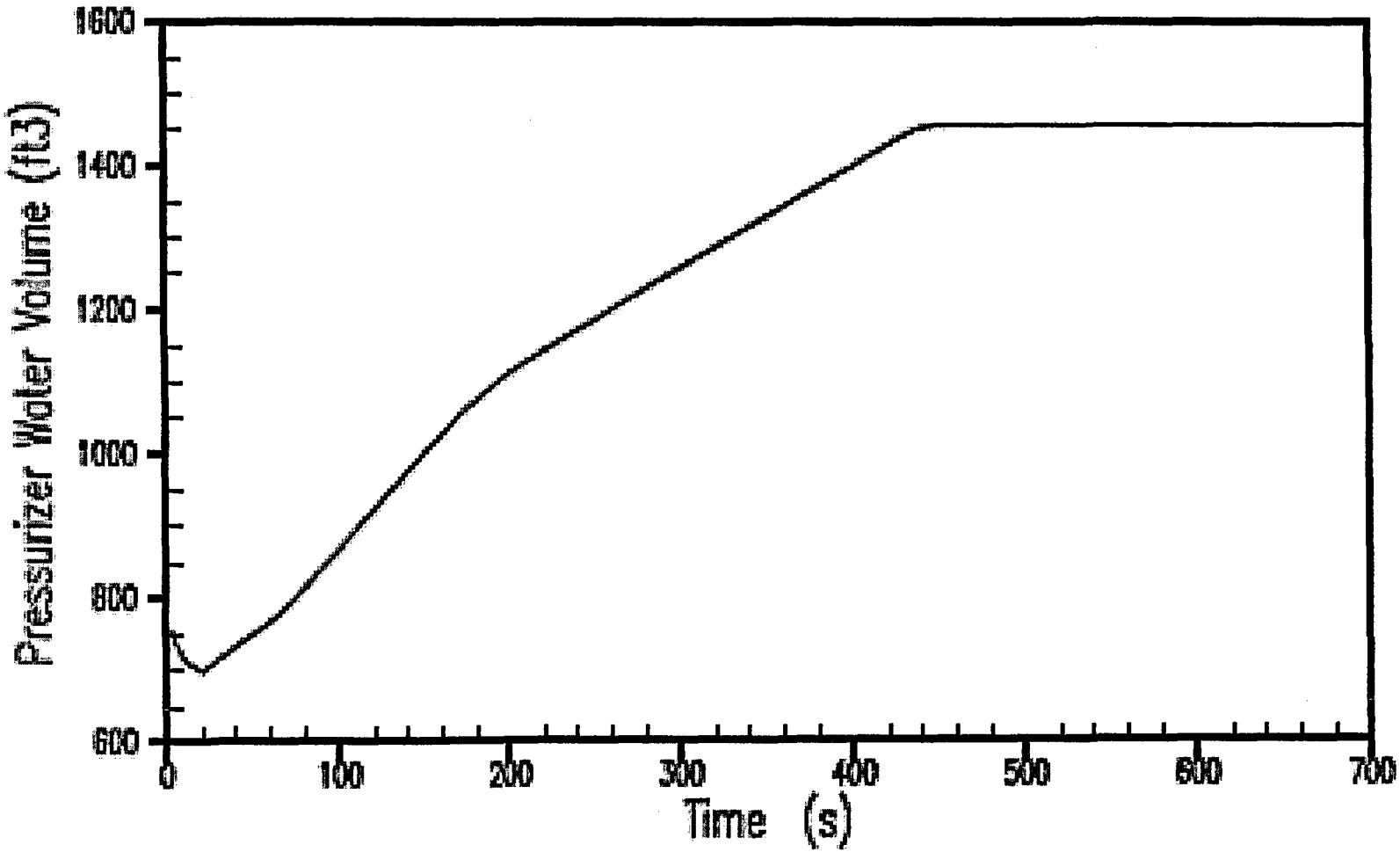
   (W-3 or WRB-1 used for outside approved range)


BEAVER VALLEY UPRATING
TT/RT From Full Power
Pressurizer Pressure vs. Time
PPrz
PRESSURE (Psia)
2400
2300
2200
2100
2000
1900
0
200
400
600
800
1000
1200
TIME (SECONDS)

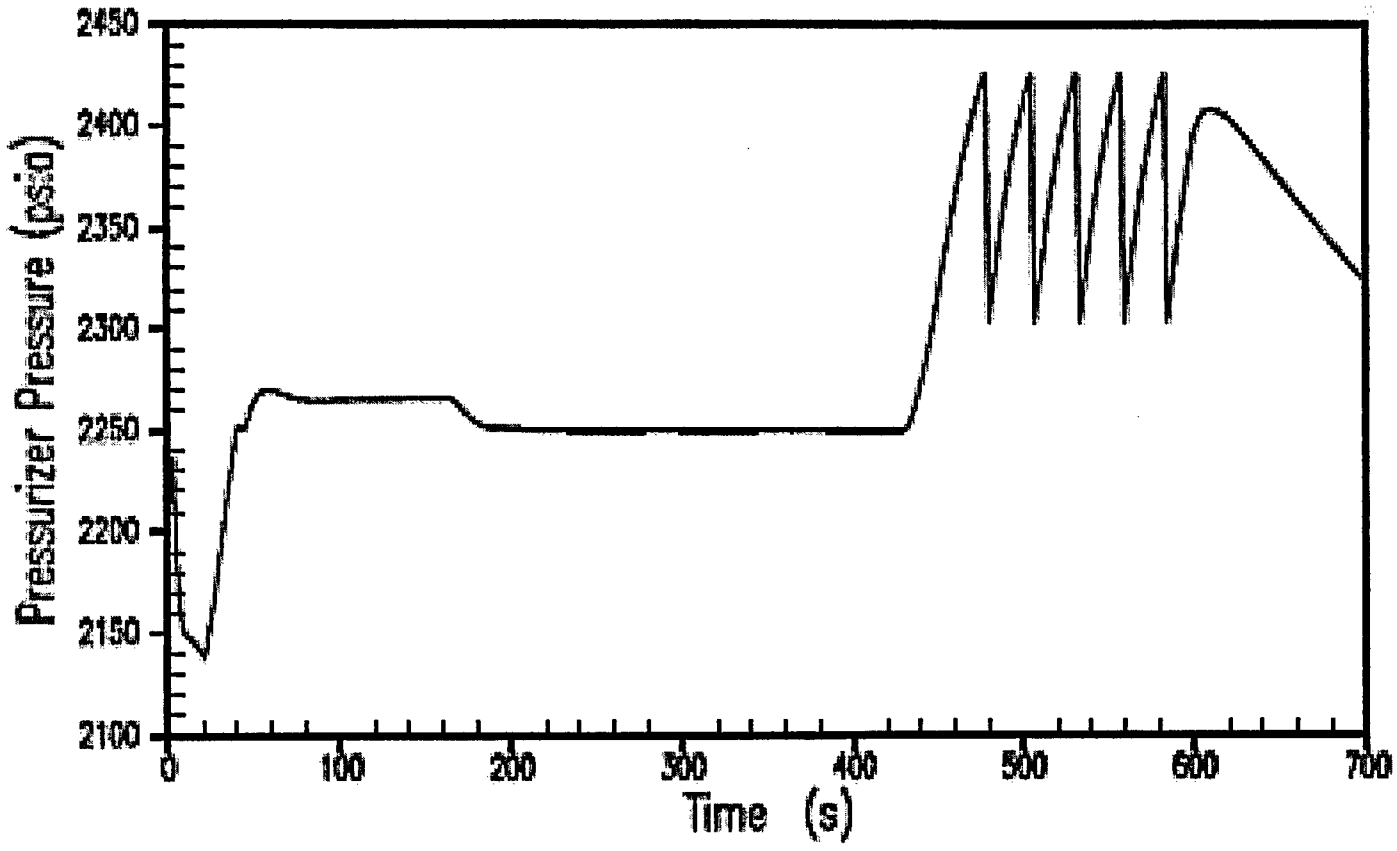
EPU


BEAVER VALLEY UPRATING
TT/RT From Full Power
Pressurizer Pressure vs. Time
PPrz
PRESSURE (Psia)
2400
2300
2200
2100
2000
1900
0
200
400
600
800
1000
1200
TIME (SECONDS)

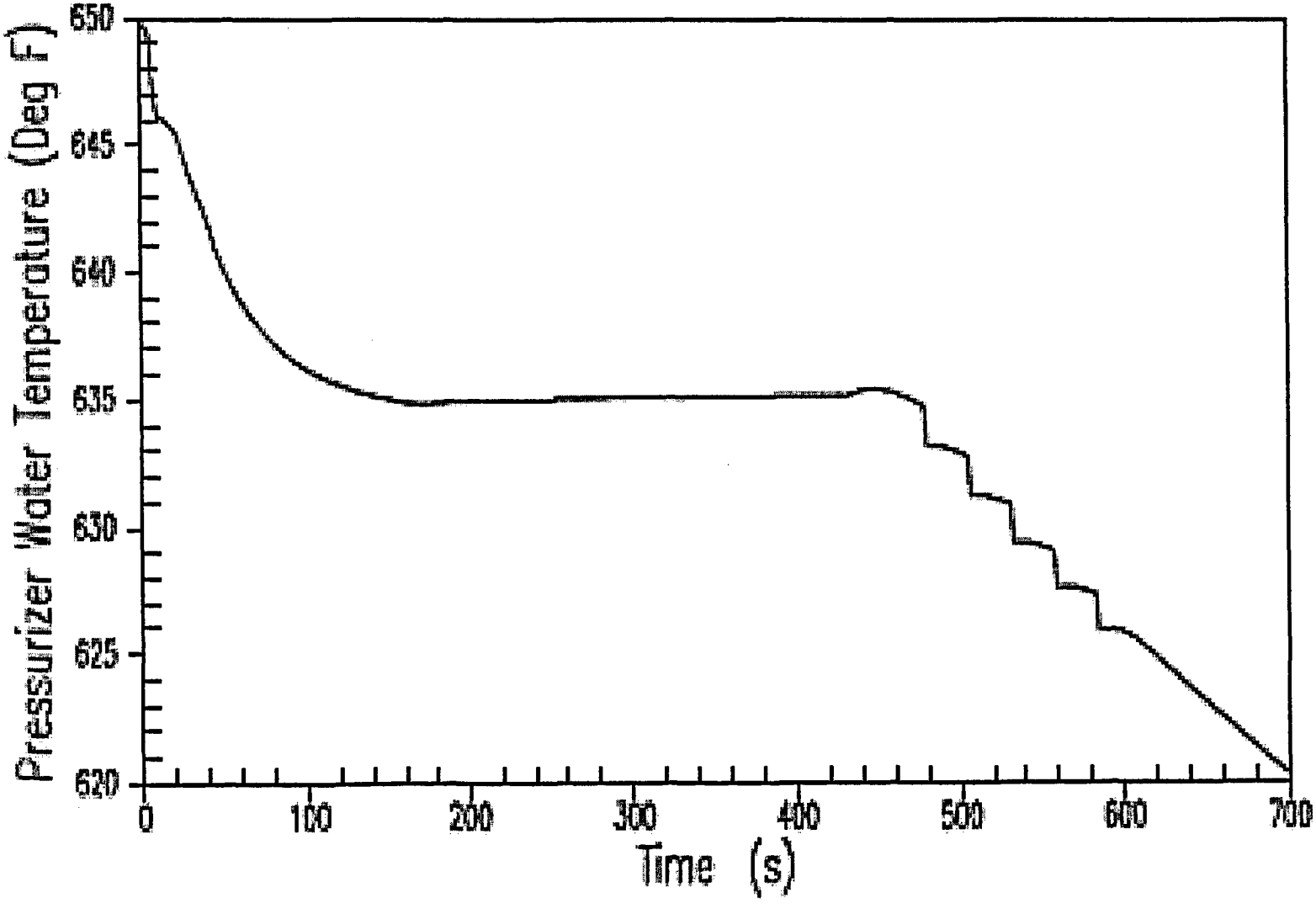
Pre-EPU



BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time



BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time



BVPS-2 Spurious SI with Pressurizer Heaters On –Pressurizer Water Temperature vs. Time

BELOCA Methodology

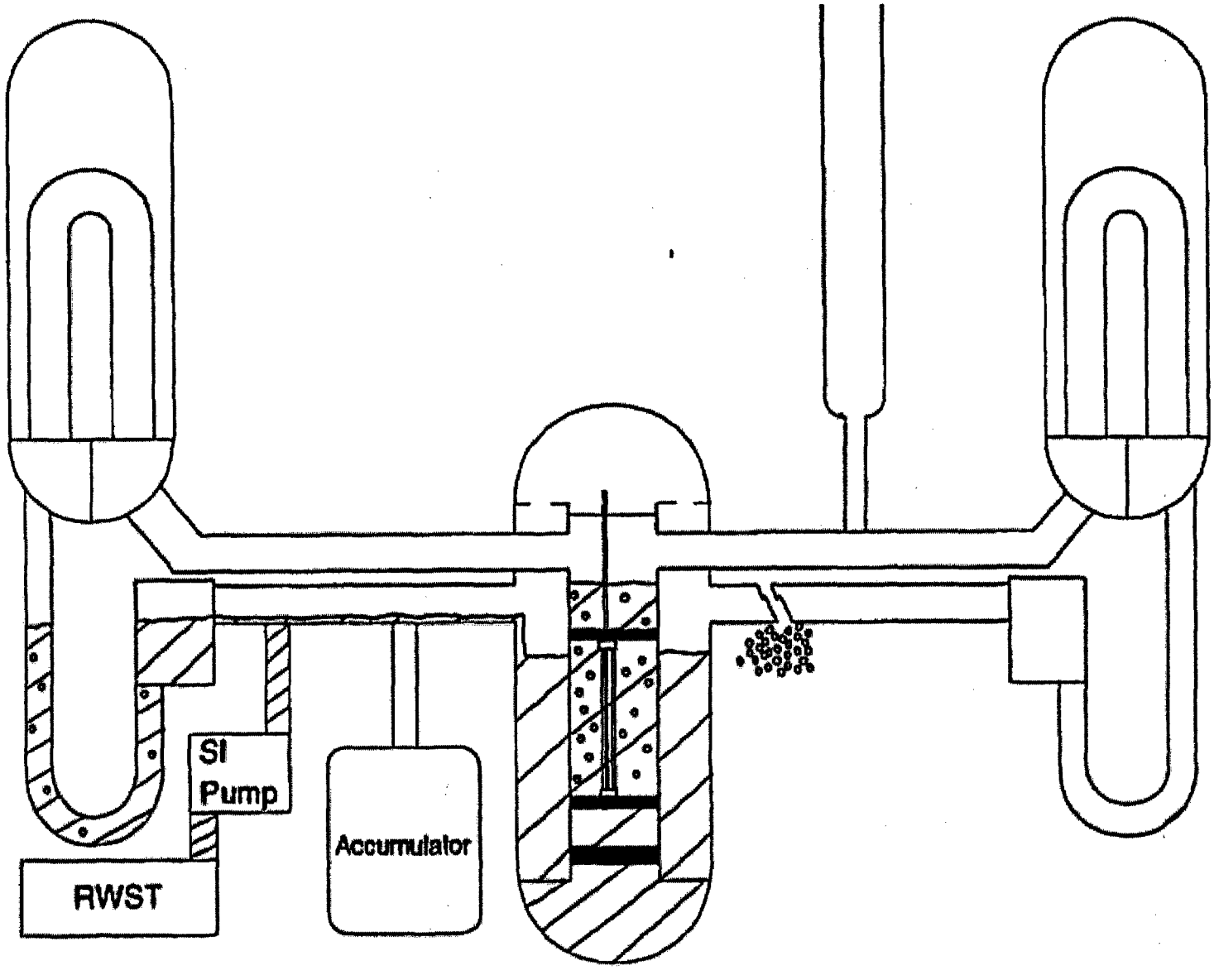
The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

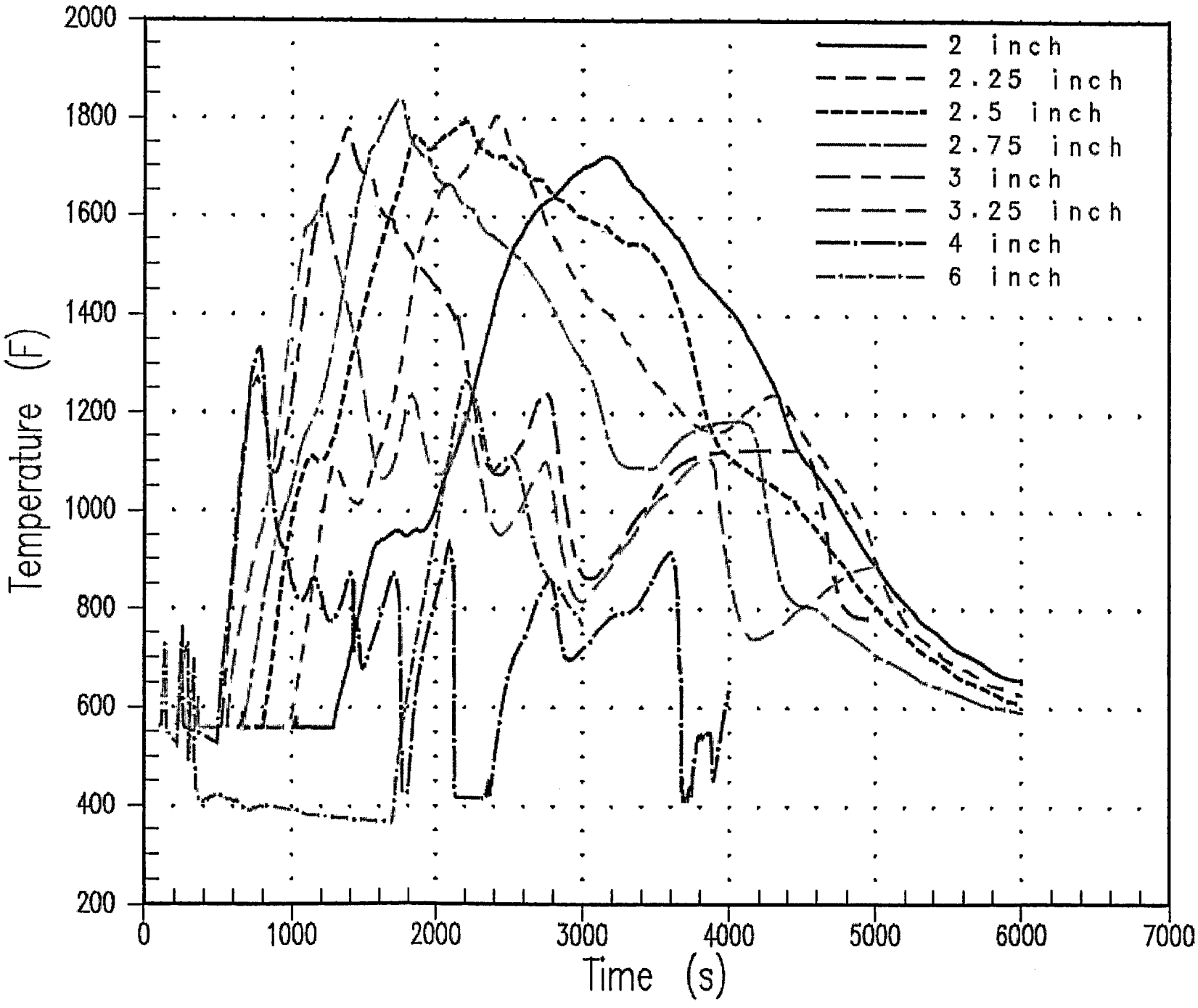
- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

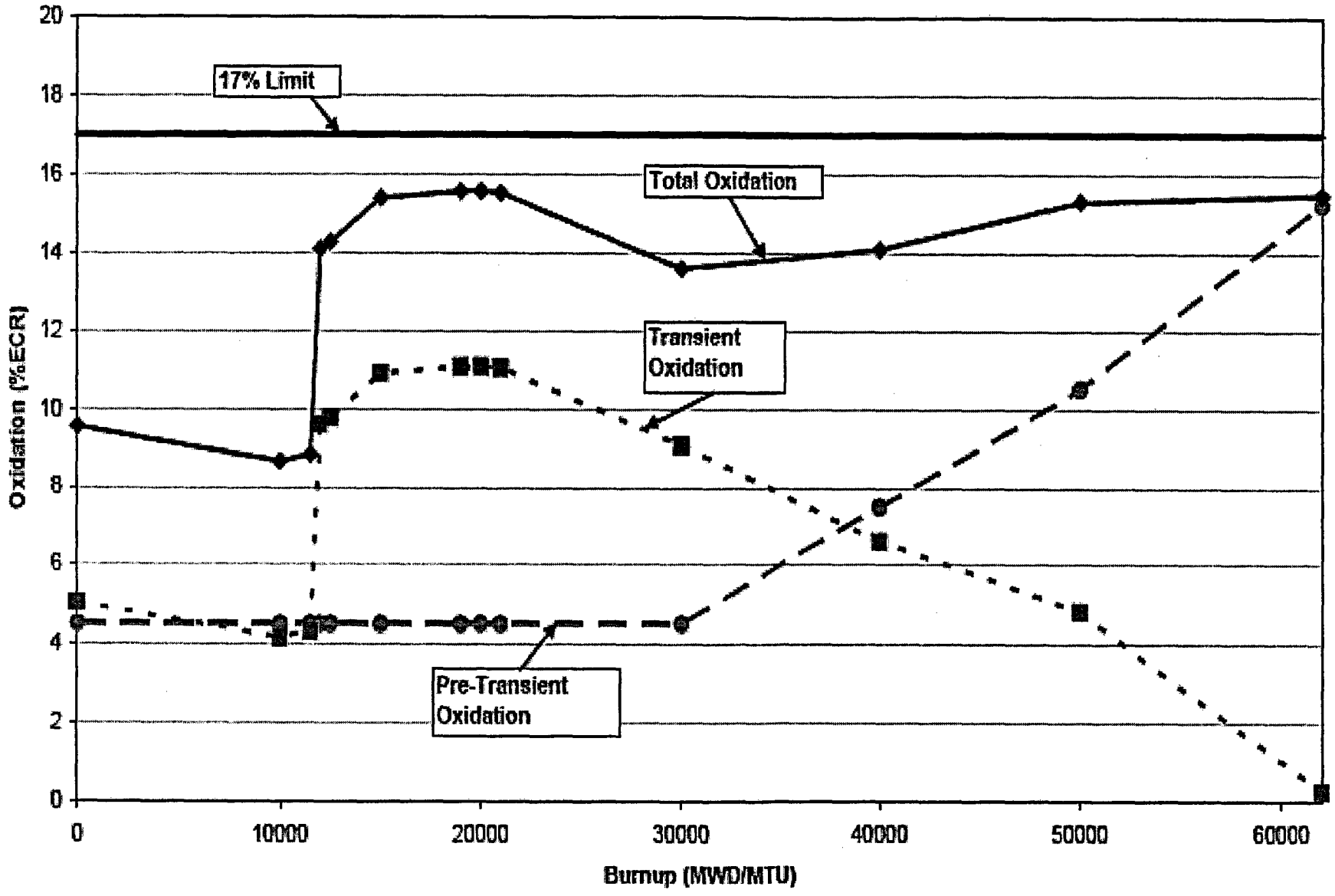
- Other inputs are treated statistically as follows
- Nominal values used to establish a reference transient
- Sensitivities are developed based on specified operating range
- 95/95 PCT is established using monte-carlo sampling over desired operating range
- Uncertainties are grouped into three categories:
  - Model parameter bias and uncertainty
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to establish 95th percentile PCT

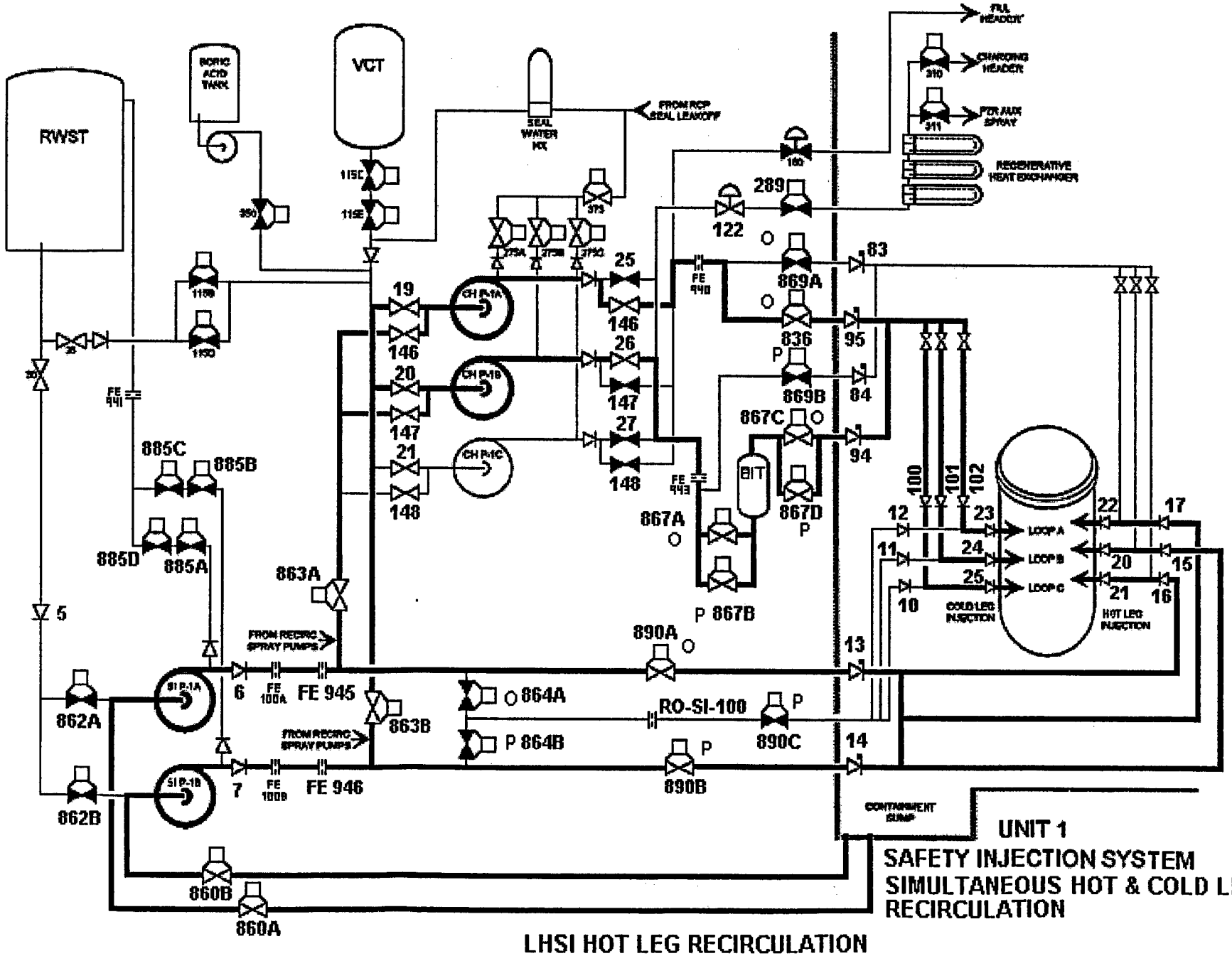
$$PCT_{95} = PCT_{REF} + \Delta PCT_{MOD} + \Delta PCT_{PD} + \Delta PCT_{IC} + \text{Superposition Correction}$$


SI
Pump
Accumulator
RWST

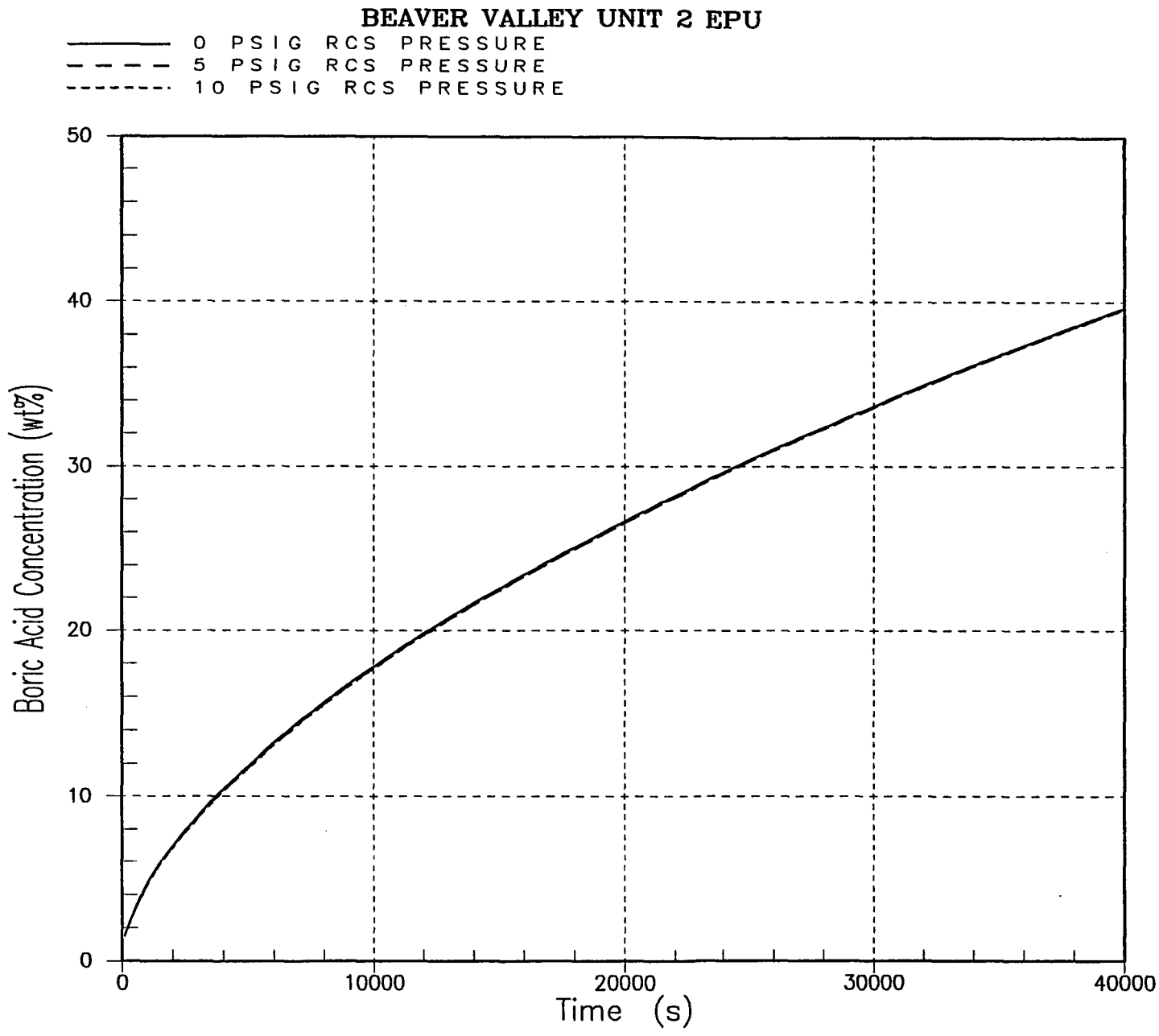

2 inch
2.25 inch
2.5 inch
2.75 inch
3 inch
3.25 inch
4 inch
6 inch
Temperature (F)
Time (s)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1000
2000
3000
4000
5000
6000
7000

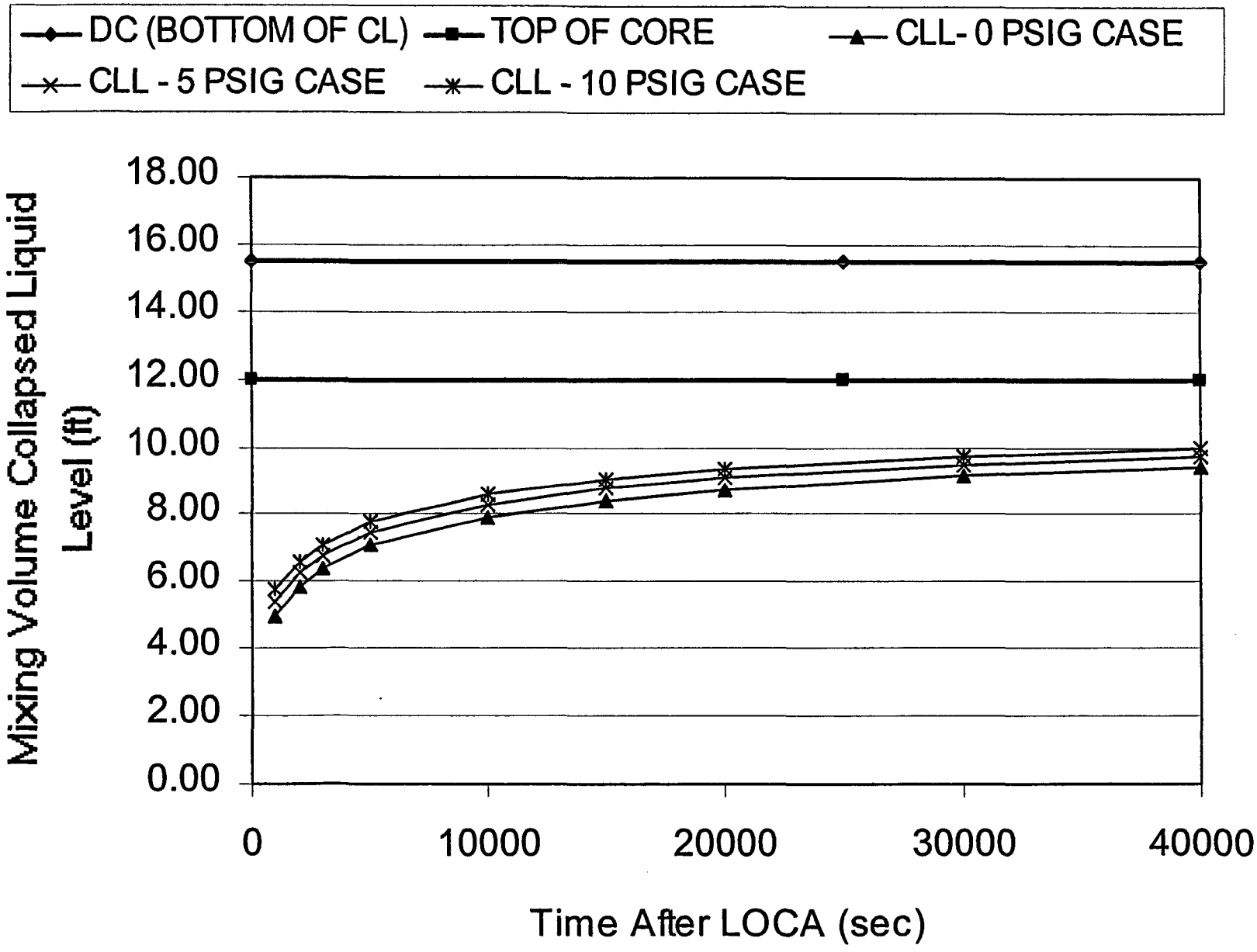
Pre-Transient, Transient and Total Oxidation vs. Burnup for Sample SBLOCA Evaluation

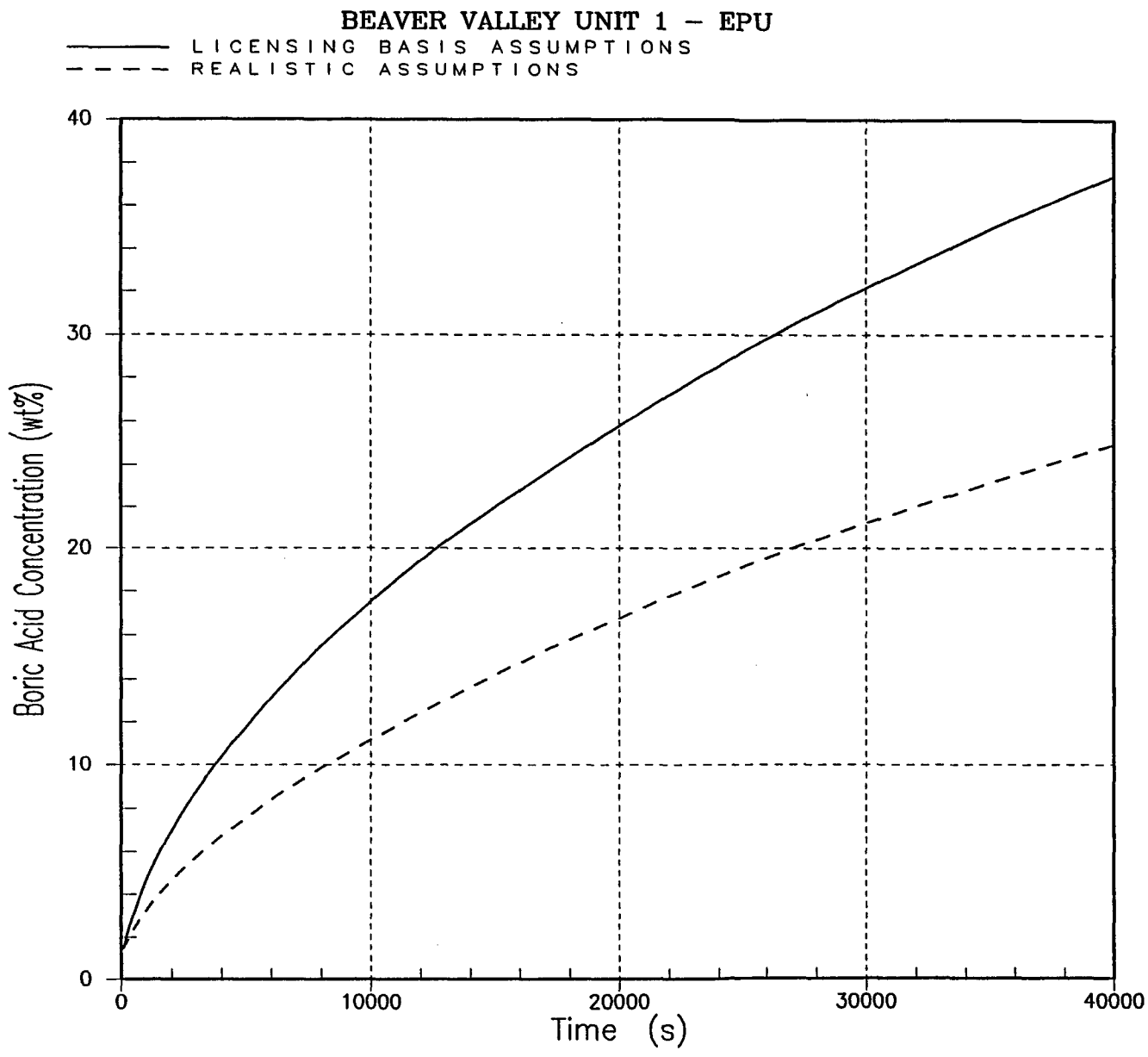




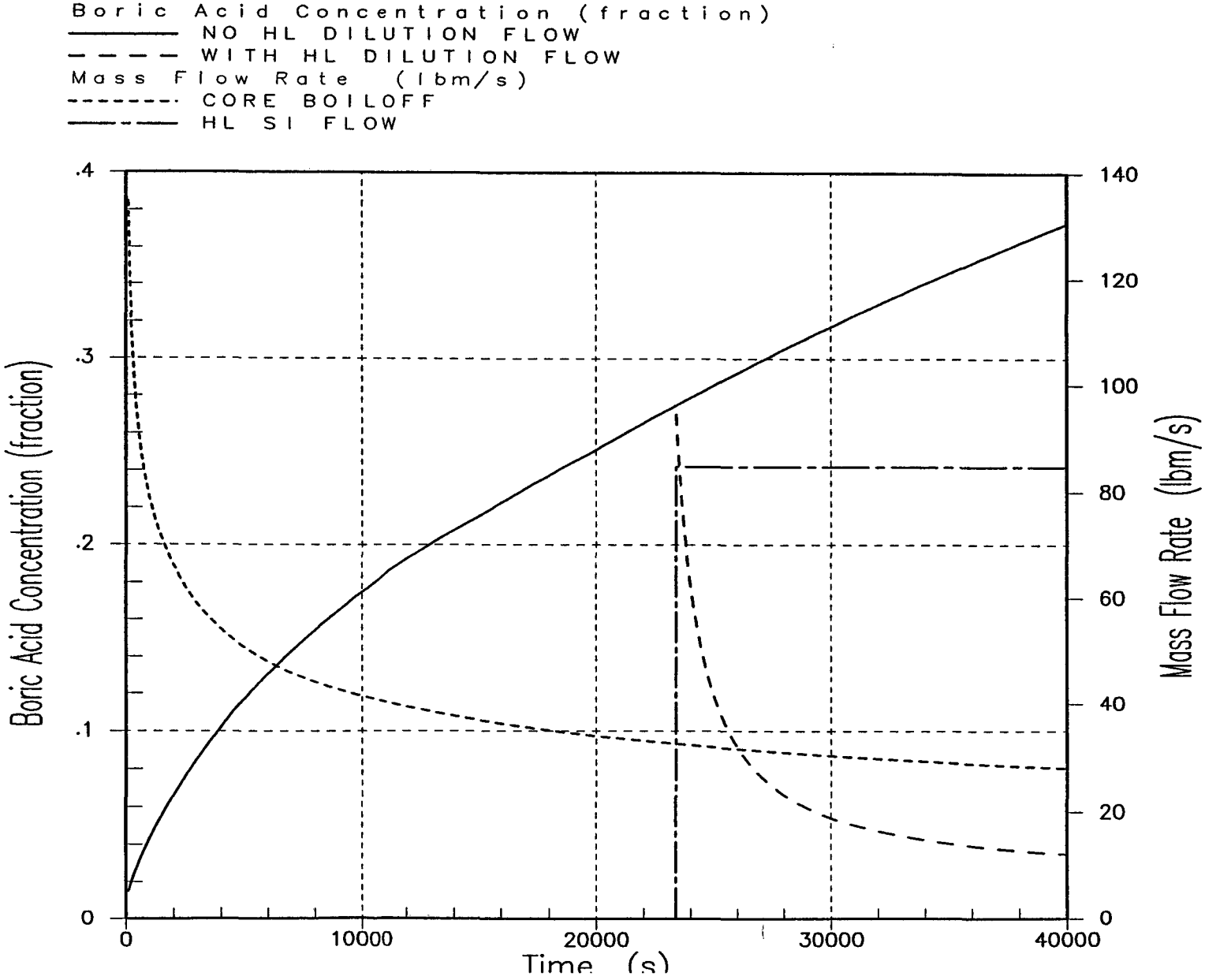
LHSI HOT LEG RECIRCULATION

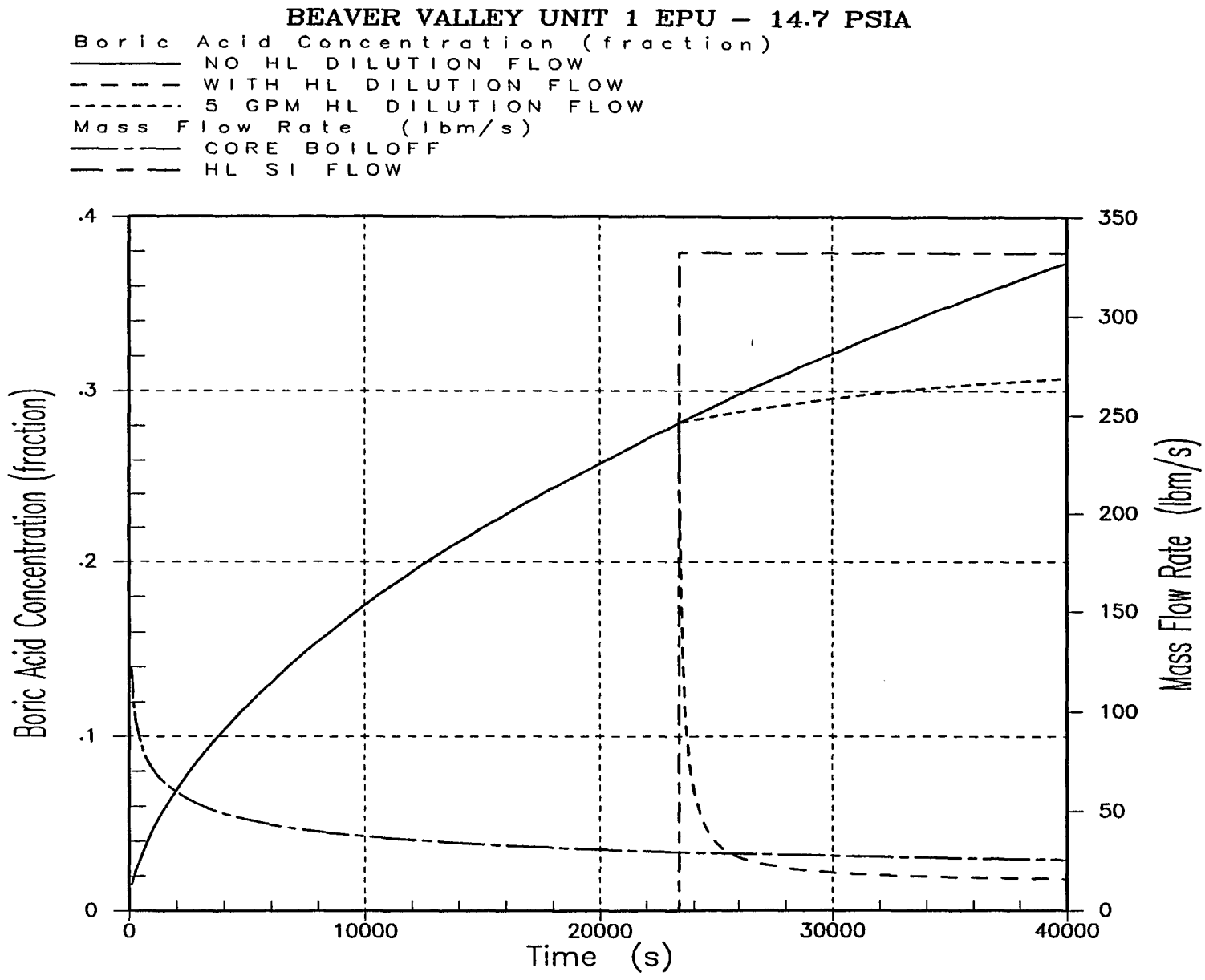

BEAVER VALLEY UNIT 2 EPU
0 PSIG RCS PRESSURE
5 PSIG RCS PRESSURE
10 PSIG RCS PRESSURE
Boric Acid Concentration (wt%)
0
10
20
30
40
50
0
10000
20000
30000
40000
Time (s)

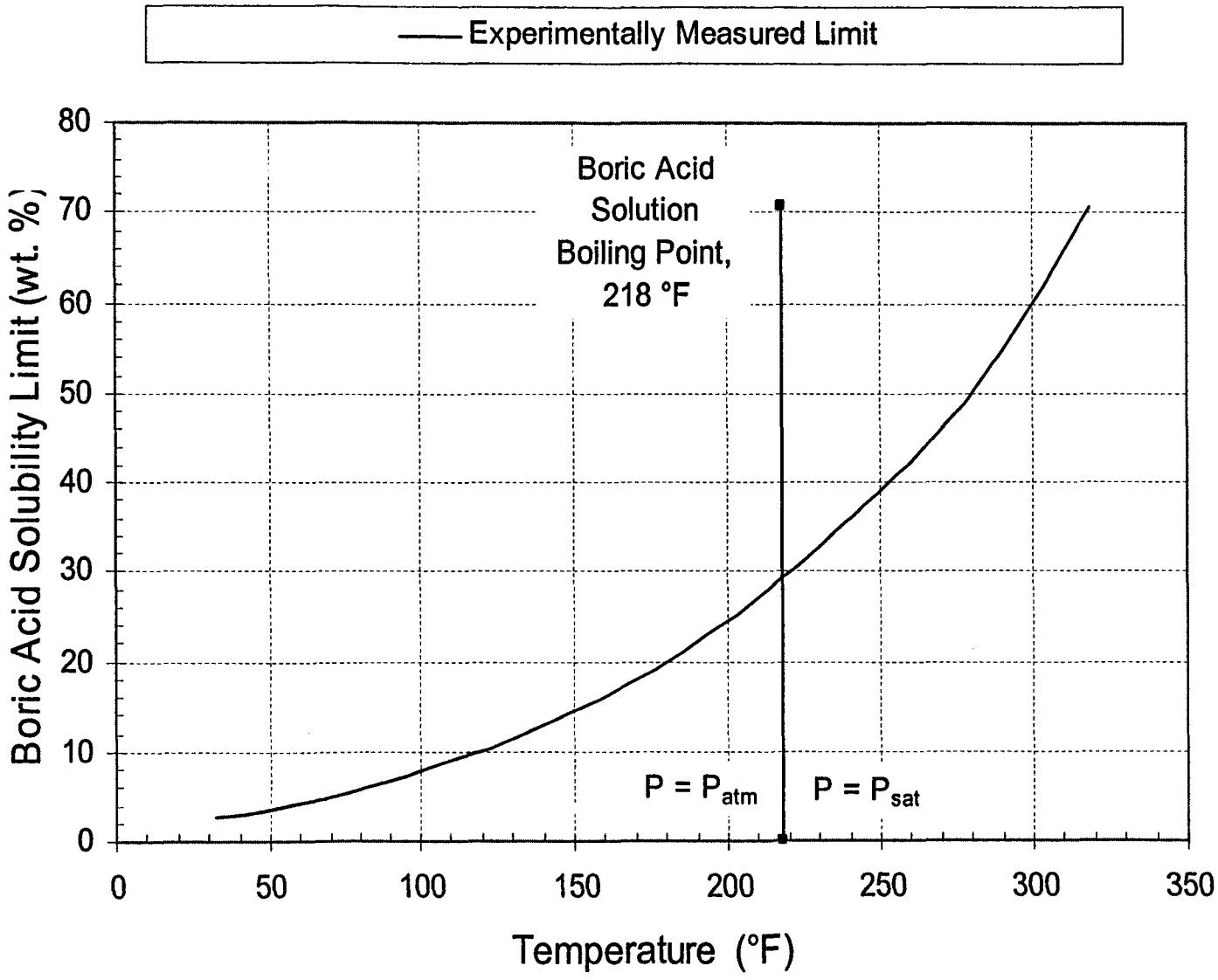

DC (BOTTOM OF CL)
TOP OF CORE
CLL- 0 PSIG CASE
CLL - 5 PSIG CASE
CLL - 10 PSIG CASE
Mixing Volume Collapsed Liquid Level (ft)
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
10000
20000
30000
40000
Time After LOCA (sec)


BEAVER VALLEY UNIT 1 – EPU
LICENSING BASIS ASSUMPTIONS
REALISTIC ASSUMPTIONS
Boric Acid Concentration (wt%)
40
30
20
10
0
0
10000
20000
30000
40000
Time (s)

BEAVER VALLEY UNIT 1 EPU – 120 PSIA

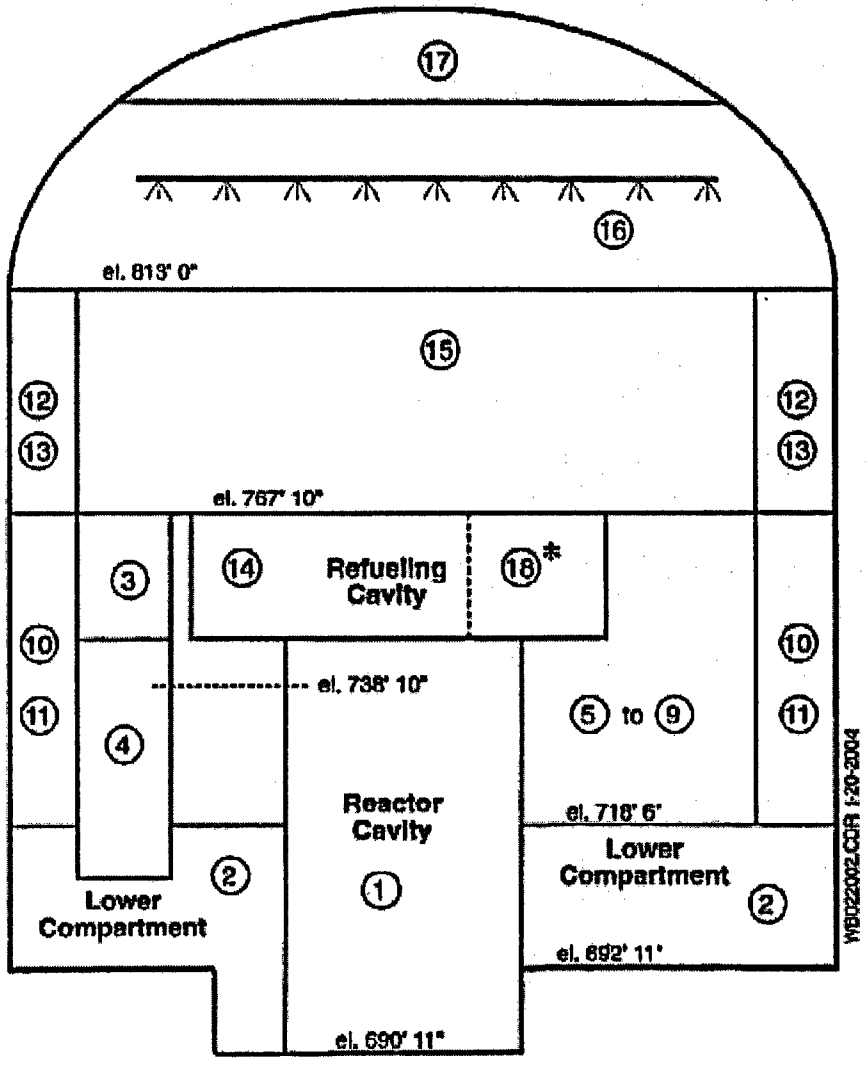



BEAVER VALLEY UNIT 1 EPU – 14.7 PSIA
Boric Acid Concentration (fraction)
NO HL DILUTION FLOW
WITH HL DILUTION FLOW
5 GPM HL DILUTION FLOW
Mass Flow Rate (lbm/s)
CORE BOILOFF
HL SI FLOW
Boric Acid Concentration (fraction)
Mass Flow Rate (lbm/s)
Time (s)
.4
.3
.2
.1
0
350
300
250
200
150
100
50
0
0
10000
20000
30000
40000

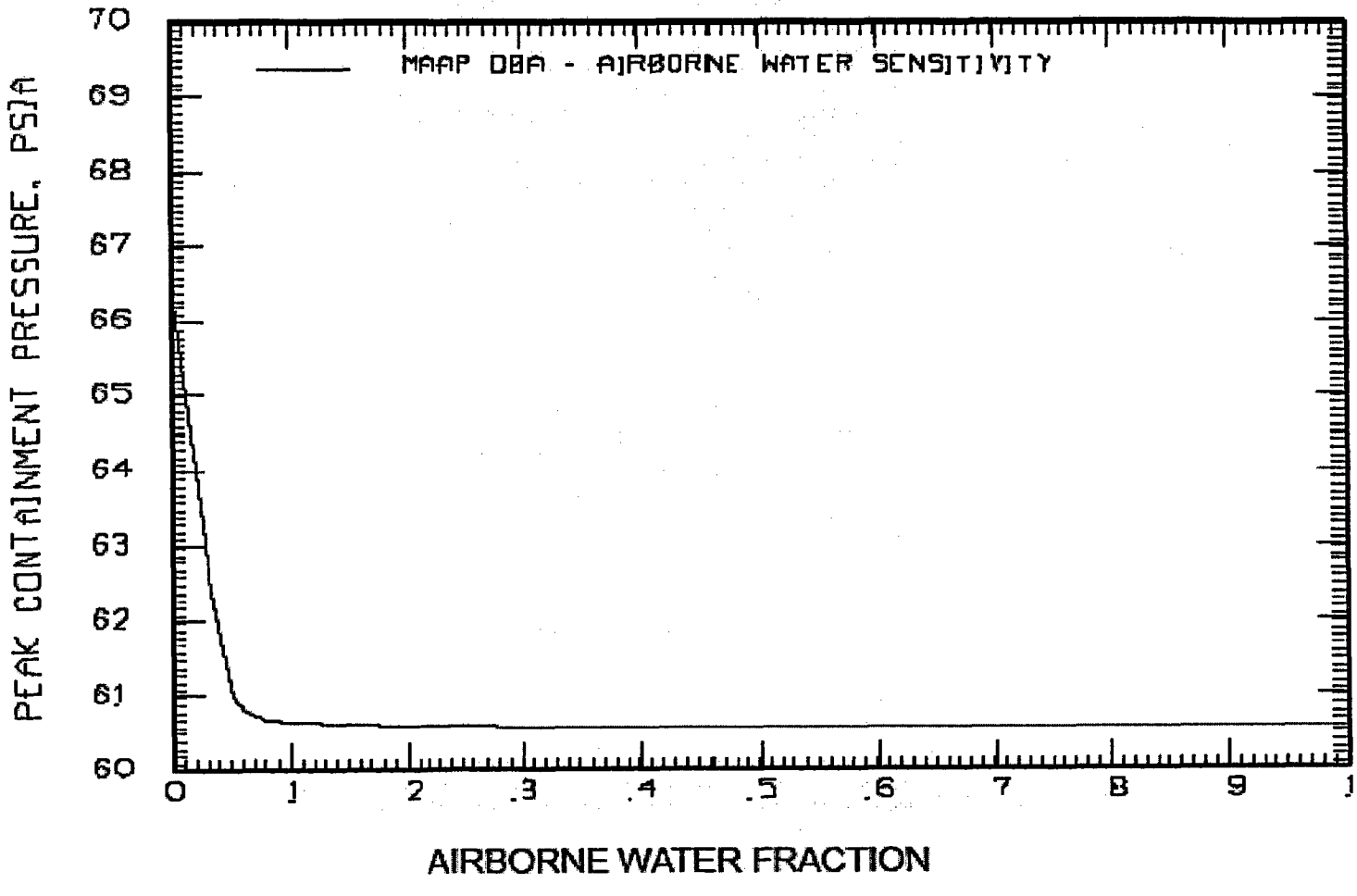


Boric Acid Solubility Limit vs. Temperature [Cohen, 1969]

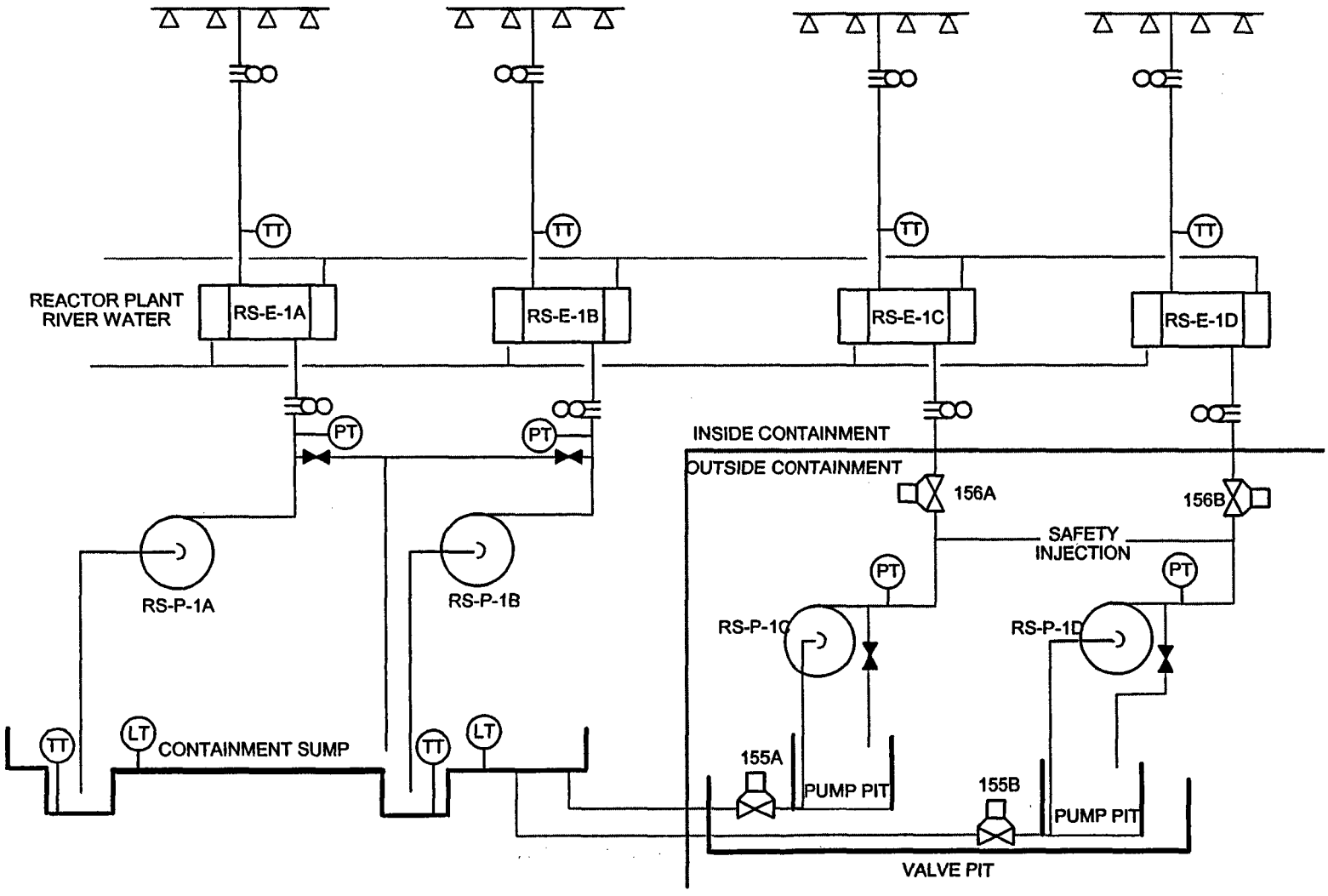
BVPS Multi-Node Containment Model



Sensitivity of Containment Pressure to LOCA Airborne Water Fraction



RECIRCULATION SPRAY SYSTEM



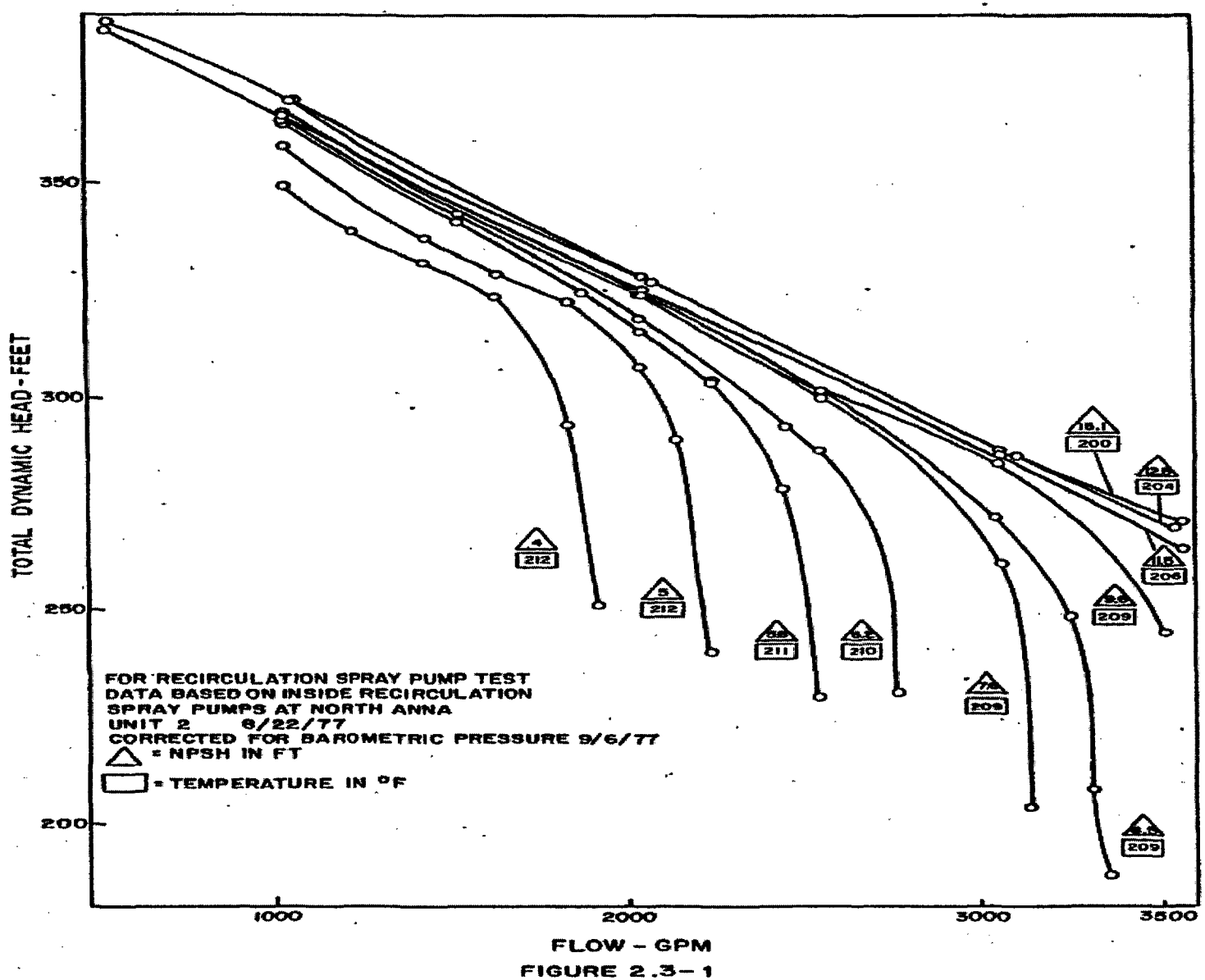
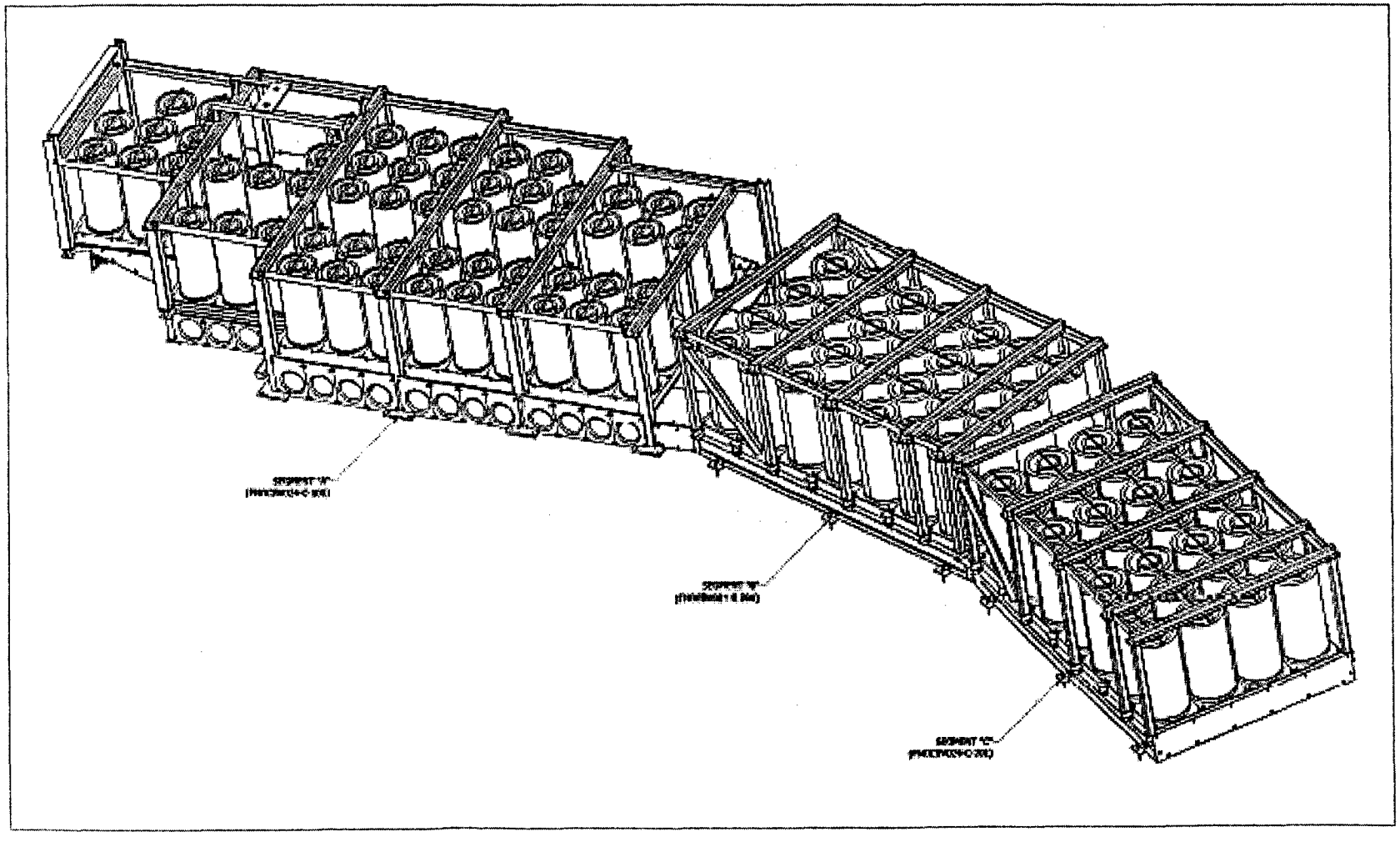


FIGURE 2.3-1
TOTAL DYNAMIC HEAD vs FLOW RATE FOR
RS PUMP TEST, NORTH ANNA 8/22/77
BEAVER VALLEY UNIT 1
DUQUESNE LIGHT CO.

Containment Sump Upgrades

- **Walkdowns of Unit 1 & Unit 2 Containments completed during refueling outages**
- **Re-analysis using NEI methodology ongoing**
- **Plant-specific debris head loss prototype testing in progress**
- **Plan to replace existing sump screens (about 120 sq. ft.) with much larger (more than 3,000 sq. ft.) strainers during next outages**
  - –Unit 2, fall 2006
  - –Unit 1, spring 2007
- **Planned sump screen upgrades will provide increased physical safety margin**

Containment Sump Upgrades



BV-2 Steam Plugging Summary

Mechanism	# tubes plugged
ODSCC	225
PWSCC – Support Plate PWSCC - U-Bend	2 21
TSP – Volumetric	30
AVB Wear	4
FIV – Pre-Uprate / Uprate	4 / 6
Free Span	88
Admin. (other)	59

SG Stress Corrosion Cracking Unit 2

- Upper bound T-hot of 611°F is within range of currently operating Model 51 (original) SGs
- Shotpeening of hot leg tube/tubesheet region and Row 1 and 2 U-bend heat treatment prior to operation has effectively limited PWSCC development
  - 2 tubes to date with reported PWSCC at top of tubesheet expansion transition
  - No incidence of U-bend PWSCC

SG Stress Corrosion Cracking Unit 2

- Another plant with Model D4 SGs (A-600 MA tubing, full depth roll expansion) performed shotpeening and U-bend heat treatment prior to operation
  - No incidence of Row 1, 2 U-bend PWSCC
  - Limited (<10) number of tubes with PWSCC at expansion transition
  - T-hot = 620°F
  - 13.2 EFPY at last inspection

SG Stress Corrosion Cracking Unit 2

- T-hot increase to 611°F from 608°F should increase ODSCC growth rates by about 7%, initiation rate by 9%
- BVPS Unit 2 ODSCC growth rates are low; number of affected tubes per outage is low for SGs of similar accumulated EFPY and tubing material.
  - Circumferential ODSCC PDA (Percent Degraded Area) growth of 10% at 95% probability
  - Growth rate should be <11% at 611°F
  - Circumferential SCC structural limit is approximately 73%

SG Stress Corrosion Cracking Unit 2

- Number of affected tubes with ODSCC at top of tubesheet is small
- Peak ODSCC +Pt coil amplitude of about 0.5V (all data) is well below in situ screening leakage threshold of 1V for axial ODSCC, 1.25V for circumferential ODSCC
- From 2R04 through 2R11;
  - 70 tubes with axial ODSCC
  - 116 tubes with circumferential ODSCC

SG Stress Corrosion Cracking Unit 2

- Extremely low incidence of axial ODSCC at tube support plate intersections
- From 2R08 though 2R11: 10 tubes confirmed with axial ODSCC at TSP intersections and plugged
- If GL 95-05 were implemented, none of these would have required plugging (<2V signal amplitude)
- TSP ODSCC average voltage growth rate <0.1V per cycle

SG Stress Corrosion Cracking Unit 2

- Row 3 to 10 Oblique PWSCC (first observed at Diablo Canyon in 2003)
- 100% Row 3 through 10 U-bends inspected with +Pt coil at 2R10; no degradation detected
- 20% sampling Row 3 through 10 at 2R11; no degradation detected
- Mechanism is highly stress dependent resulting in limited flawed arc lengths, typically <60 degrees arc
- T-hot of 611°F judged to have minimal impact based on observed history to date

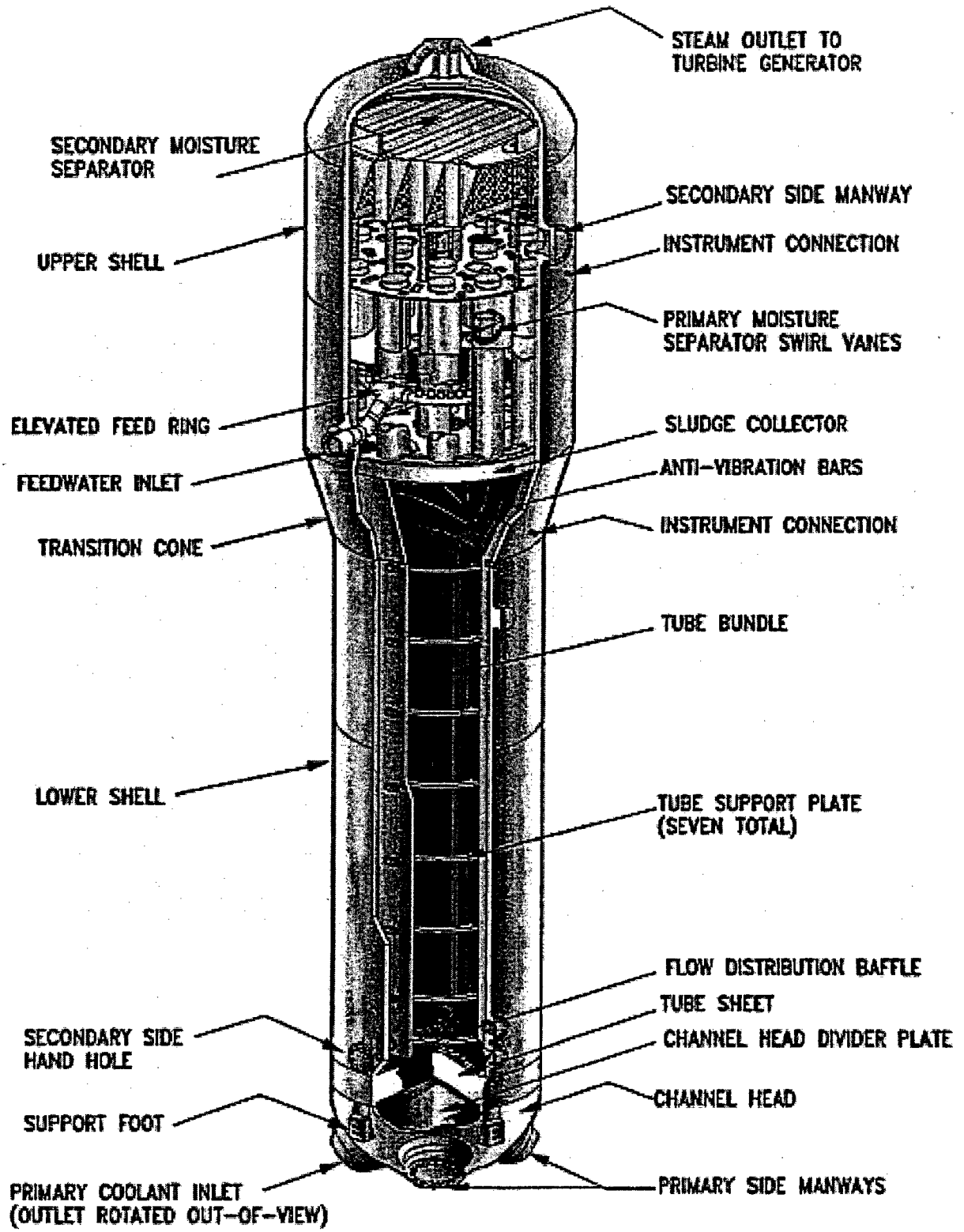


Figure 4.7-1
BVPS-1 Replacement Steam Generator

S/G Comparison

Plant	NSSS Power Level (MWt)	# of Loops	# of Steam Separators	S/G Model
BVPS-1 BVPS-2	2910 * 2910 *	3 3	1-tier 2-tier	54F 51M
Farley 1&2	2785	3	1-tier	54F
ASCO 1&2	2952	3	2-tier	D3
North Anna 1&2	2905	3	2-tier	54F -lower 51-upper
Shearon Harris	2912	3	1-tier	Delta 75
Vandellos 2	2954	3	2-tier	F
V.C. Summer	2912	3	1-tier	Delta 75

* Proposed

RHR / CCW System Heat Loads

Case	# of trains	Final RCS temp.	BV-1 (time)	BV-2 (time)
Normal cooldown	2	140 F	34 hrs.	51 hrs.
Single train cooldown	1	200 F	NA	57.9 hrs.
UFSAR App. 5A (natural circulation)	Aux. FW / SG PORVs to cut-in 2 RHR trains	200 F	NA	43 hrs.
Appendix R cooldown	See note	200 F	< 127 hrs.	< 72 hrs.

Note: 2 trains credited for BVPS-2. RHR not credited for BVPS-1.

Auxiliary Feedwater

Condition	Flow	BV1 pre-EPU	BV1 post - EPU	BV2 pre-EPU	BV2 post-EPU
Feed Line Break (FLB)	# pumps	1 /3	2/3	2/3	2/ 3
	Flow (gpm)	300	250 / 400	250 / 400	250 / 400
Loss Normal Feed (LONF)	# pumps	1/3	2/3	2/3	2/3
	Flow (gpm)	350	489	300	489

Mechanical Impacts – Flow Accelerated Corrosion

System	Description	Component ID	Component Geometry	Pipe Class	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Wear-Rate 110% (EPU) Power (mils/year)
		Significant Velocity Change				
BVPS-1: Heater Drain	4th Point Heater Drain Line	1-W4D-01-13T (Br) 1-W4D-01-14E 1-W4D-01-14EP 1-W4D-01-13TP 1-W4D-01-16N	Tee Elbow Pipe Pipe Nozzle	151	1.489 1.620 1.094 0.876 0.820	2.050 1.820 1.216 1.154 1.055
BVPS-2: Heater Drain	4th Point Heater Drain Line	2HDL-008-08-1R(S/E) 2HDL-006-58-1P 2HDL-008-11-1R(L/E) 2HDP-008-08-5N 2HDP-008-11-5N	Reducer Pipe Reducer Nozzle Nozzle	601	2.079 1.646 1.435 0.899 0.899	2.412 1.918 1.683 1.103 1.103

Probabilistic Risk Assessment

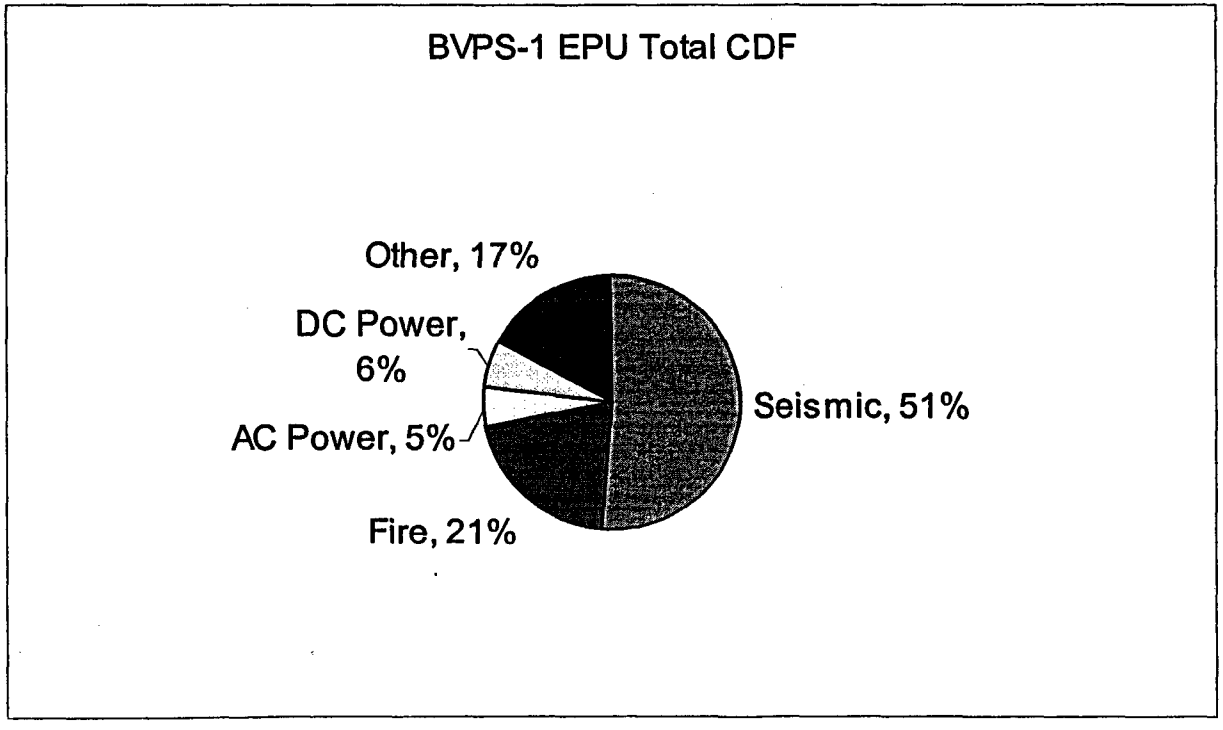
BVPS-1 Post-EPU Operator Actions with Short Time Available			
Description	Total Time Available	Cue Time	Action Time
Operator depressurizes the RCS via ASDVs	2.68 hours	30 minutes	9 minutes
Operator depressurizes the RCS via ASDVs given HHSI failed and AC Orange failed	72 minutes	20 minutes	9 minutes
Operators initiate bleed and feed operation	42 minutes	10.4 minutes	4 minutes
Same as OPROB1 except the operators fail to restore MFW and the dedicated AFW.	29 minutes	8.5 minutes	7 minutes
Operator manually starts and aligns auxiliary river water pumps.	13 minutes	2 minutes	3 minutes
Operator manually stops the EDG and aligns the diesel-driven fire pump.	1 hour	2 minutes	15 minutes

Probabilistic Risk Assessment

BVPS-2 Post-EPU Operator Actions with Short Time Available			
Description	Total Time Available	Cue Time	Action Time
Operator depressurizes the RCS via ASDVs (small LOCA and HHSI has failed).	72 minutes	20 minutes	2 minutes
Operator depressurizes the RCS via ASDVs, given HHSI failure and loss of emergency AC Orange.	72 minutes	20 minutes	9 minutes
Operators initiate bleed and feed operation	64 minutes	28.3 minutes	4 minutes
Same as OPROB1 except that the actions take place after the operators fail to restore MFW and the dedicated AFW.	35 minutes	18.4 minutes	7 minutes
Operator manually stops the EDG and racks the spare service water (SWS) pump onto the bus.	1 hour	2 minutes	13 minutes
Operator aligns the diesel-driven fire pump with offsite power available.	1 hour	2 minutes	15 minutes

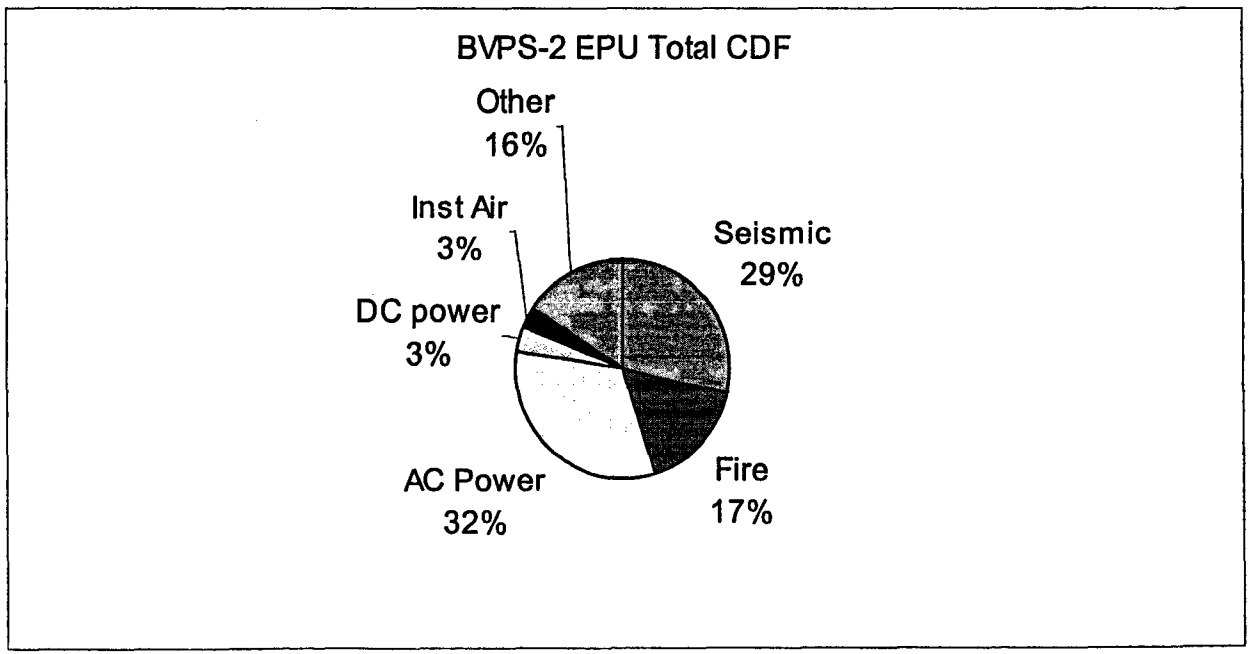
Probabilistic Risk Assessment

- **EPU Sequence Contribution to CDF (BVPS-1)**
  - **Contributors are consistent with Pre-EPU model**



Probabilistic Risk Assessment

- **EPU Sequence Contribution to CDF (BVPS-2)**
  - **Contributors are consistent with Pre-EPU model**



Examples Of Normal Operating Procedure Parameter Changes

- Control Room Logs including:
  - Containment pressure & temperature
  - Accumulator level & pressure
  - RWST temperature
  - S/G steam pressure
  - Pressurizer level
- Operator Tour Logs (BOP parameters)

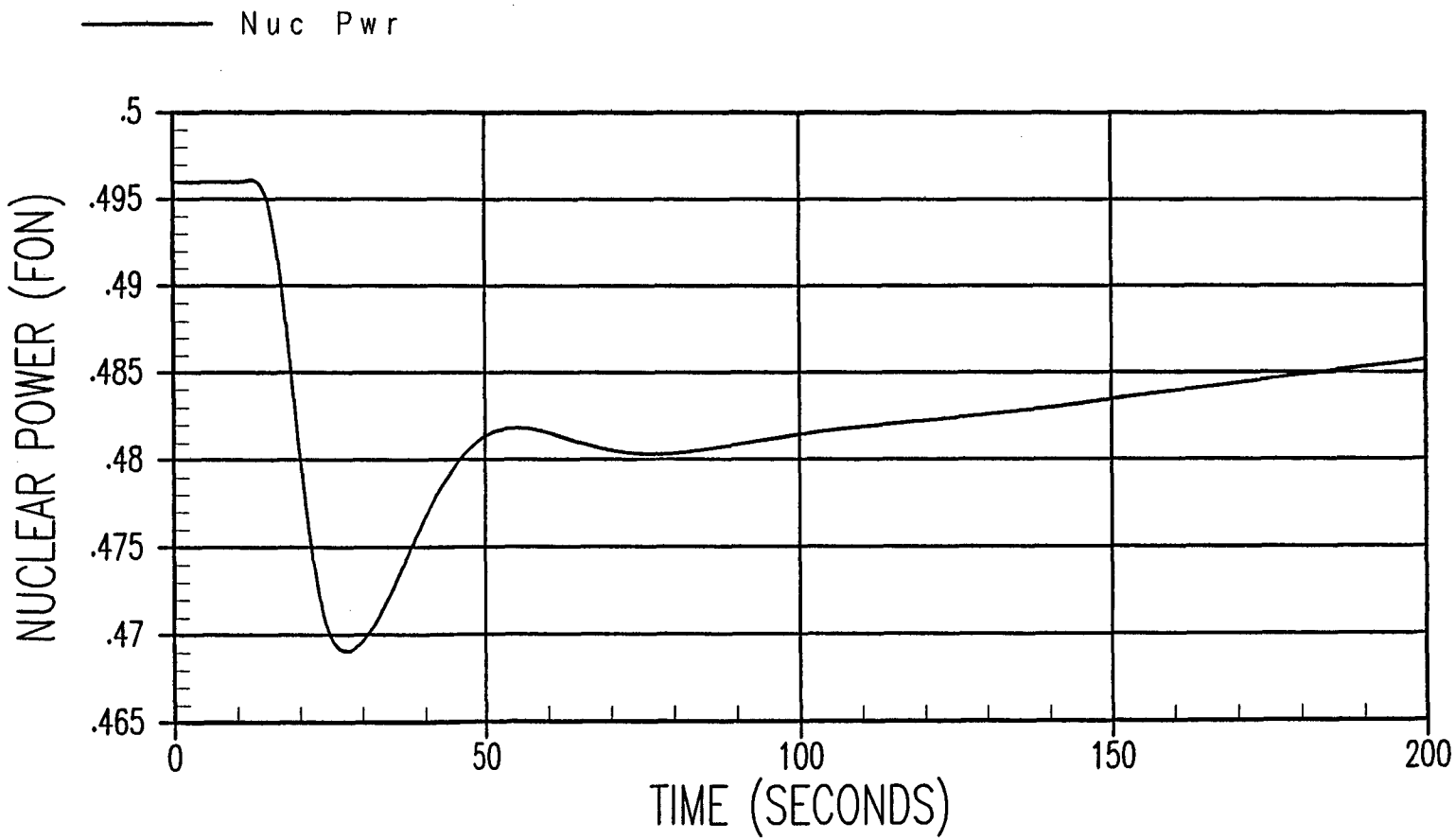
Examples of EOP Setpoint Changes

- Minimum AFW flow
- S/G Levels (BVPS-1 RSGs)
- Minimum SI flows (core boil-off)
- ECCS Switchover to Hot Leg Recirculation
- RWST Switchover (sump recirculation)
- Containment Actuation (Hi, Hi-2, Hi-3)
- RCS temperature & S/G pressure to preclude accumulator N2 injection

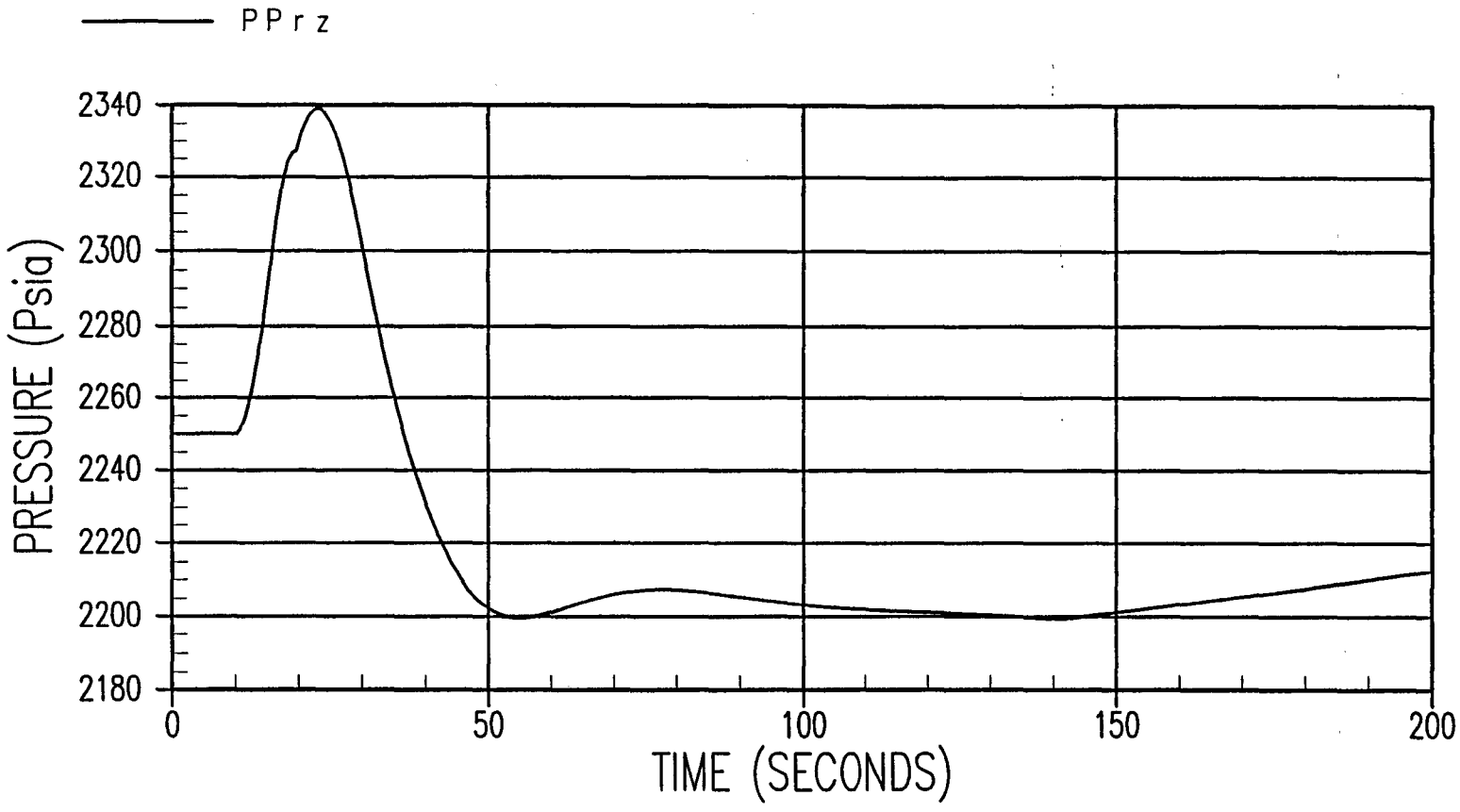
Reduced SGTR Action Times (min)

Action (following RX trip)	BV-1 Current	BV-1 EPU	BV-2 Current	BV-2 EPU
Isolate AFW flow	N/A	6.8	9.1	5.5
- Re-Validation		4.1 (sim)		5 (tt)
Isolated MSIV and initiate cool down	N/A	19.1	N/A	17
- Re-Validation		11.7(sim)		12 (tt)

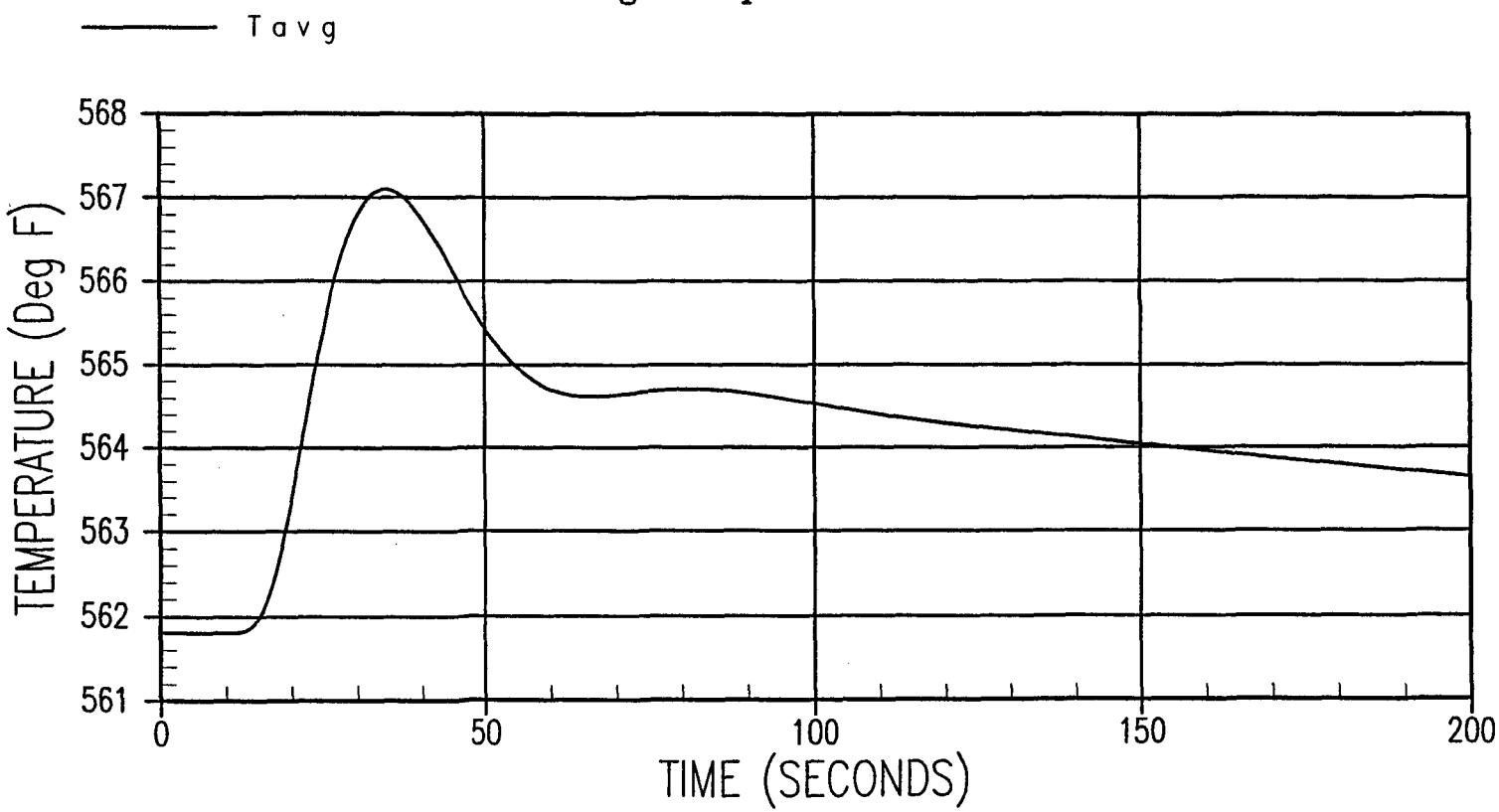
BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9). Manual RC
Nuclear Power Vs. Time



BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9). Manual RC
Pressurizer Pressure vs. Time



BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9), Manual RC
Vessel Average Temperature Vs. Time



Plant Hardware Modifications

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Replace Main transformer cooling (BVPS-2)	Performance test, In-service check	No
Replace Cooling Tower Fill (BVPS-2)	Performance test, In-service check	No
Replace heater drain level control valves/trim	Leak check, In-service check	No
Replace charging pump rotating impellors	Leak check, Performance test	No
Modify turbine plant cooling water system (remove orifice) (BVPS-2)	Leak check, In-service check	No
Replace isophase duct cooling system flow transmitters (BVPS-1)	Channel calibration, Leak check	No
Replace various BOP transmitters	Channel calibration, Leak check	No

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Add reactor cavity drains	As left check	No
Eliminate QS cutback feature (BVPS-1)	Leak check, Functional check	No
Replace S/G NR level transmitters (BVPS-1)	Channel calibration, Leak check, In-service check	No
Replace main steam and feedwater flow transmitters	Channel calibration, Leak check, In-service check	No (not used in RX trip logic)
Replace HP Turbine	Leak check, Overspeed test, Performance test, In-service check	No (isolated on RX trip)
Replace HP Turbine 1st stage pressure transmitters	Channel Calibration, Leak check, In-service check	No (not used in RX trip steam dump logic)

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Replace main generator rotor & stator rewind (BVPS-1)	Hypot test, Leak check, Torsional check, Flow test, In-service check	No
Staking of condenser tubes (BVPS-2)	Periodic tube-side inspections, In-service chemistry check	No
Change-out of main feedwater valve/trim	Stroke test, Leak check, In-service check	No (no change in partial feedwater isolation logic)
Addition of fast-acting feedwater valves (BVPS-1)	Functional check, Stroke test, Leak check, Response time test, SSPS slave relay testing	No

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
RSGs (BVPS-1)	Leak check, Moisture carryover test, Performance test	No
Addition of auxiliary feedwater flow restrictors (BVPS-1)	Leak check, Flow test	No (reduces excess cooling post-trip previously requiring operator action)
Replace accumulator pressure indicators	Channel calibration, In-service check	No
Replace containment NR pressure transmitters & indicators	Channel calibration, Leak check, In-service check	No
Addition of dynamic compensation hardware for OTDT & OPDT reactor trip functions (BVPS-1) (match BVPS-2 design)	Channel calibration	No (Pressurizer Pressure Hi RX trip would actuate)

Setpoint /Scaling Changes

Plant Modification	Post Modification Test	Further Tested by TT
Change/add OTDT & OPDT RX trip constants & time constants	Channel calibration, In-service check	No (Trip function remains along with several diverse trips)
Reduce S/G Low-Low Level RX trip & AFW actuation setpoint (BVPS-1)	Channel calibration	No
Raise S/G Hi Level FWI actuation setpoint (BVPS-1)	Channel calibration	No
Rescale pressurizer reference level (due to full-power Tavg change)	Channel calibration, In-service check	No (No change to no-load temp. & associated przr. reference level)
Rescale containment NR pressure transmitters (BVPS-1)	Channel calibration, In-service check	No

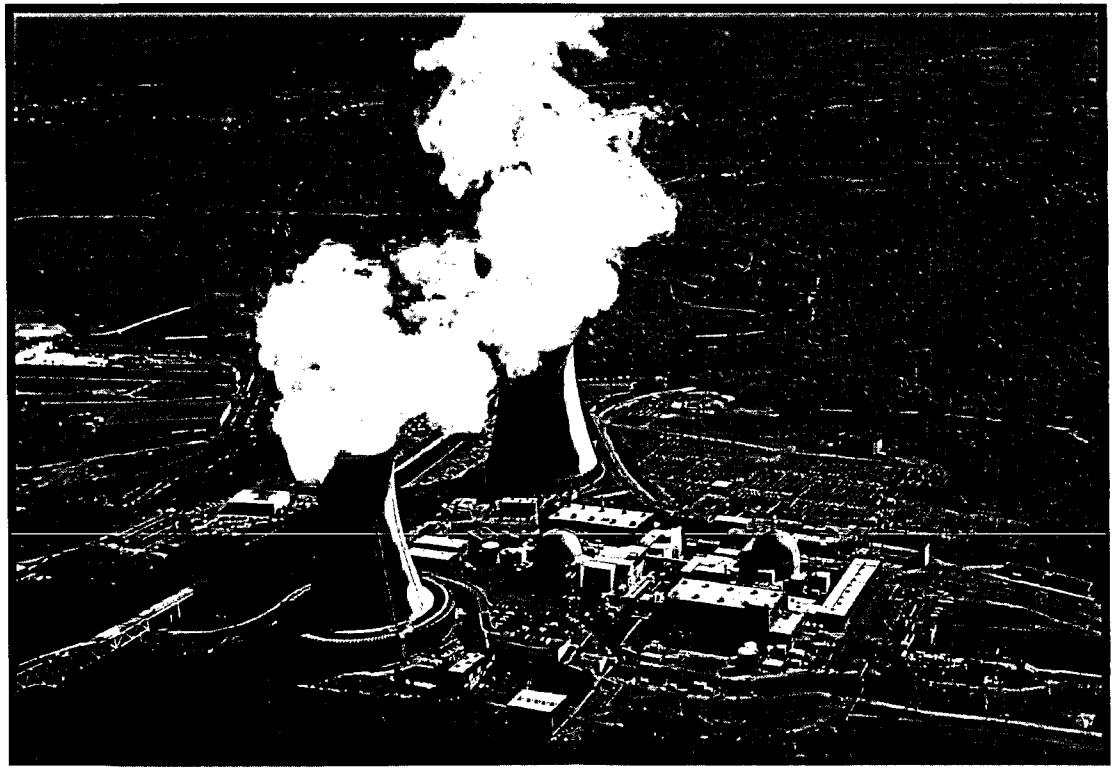
Setpoint /Scaling Changes (cont)

Plant Modification	Post Modification Test	Further Tested by TT
Revise S/G NR level control setpoint & associated alarm setpoints (BVPS-1)	Channel calibration, In-service check, Level control test	No
Revise steam dump (reactor trip controller) trip open setpoints	Channel calibration	No (No change to No-Load Temperature & associated przr. reference level)
Revise steam dump (load rejection controller) trip open & deadband setpoints	Channel calibration	No (Not in-service on turbine trip)
Revise steam dump C-7B setpoint (Large Load Rejection / 4 bank operation)	Channel calibration	No (Not in-service on turbine trip)

Setpoint /Scaling Changes (cont)

Plant Modification	Post Modification Test	Further Tested by TT
Revise Demineralizer Water Storage Tank control & alarm setpoints (BVPS-2)	Channel calibration, In-service check	No
Revise BOP instrument scaling	Channel calibration	No
Revise MSR relief valve setpoint	Bench test, Leak check, In-service check	No (isolated on turbine trip)
Revise RWST level switchover setpoint & RWST Hi temperature alarm setpoint	Channel calibration, In-service check	No
Rescale accumulator pressure & level and revise alarm setpoints	Channel calibration	No
Revise containment pressure ESFAS actuation setpoints (Hi, Hi-2, Hi-3)	Channel calibration	No

BEAVER VALLEY POWER STATION
Extended Power Uprate



ACRS Thermal Hydraulic Subcommittee

April 25-26, 2006

FENOC

FirstEnergy Nuclear Operating Company

Introduction

Jim Lash
Site Vice President

FENOC
FirstEnergy Nuclear Operating Company

Agenda

• Introduction	• Jim Lash
• Overview	• Pete Sena
• Plant Changes	• Mark Manoleras
• Rx Fuel & Core Design	• A.R. Burger
• Safety Analysis	• Ken Frederick
• Materials & RV Integrity	• Dennis Weakland
• Mechanical Plant (BOP)	• Mike Testa
• Risk Evaluation	• Colin Keller
• Operations & Testing	• Don Durkosh
• Conclusion	• Jim Lash

Introduction - Agenda

- Beaver Valley History
- EPU Timeline
- Beaver Valley Peer Units
- Oversight

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley History

- Beaver Valley Power Station Units 1 and 2
- Westinghouse NSSS 3 loop Pressurized Water Reactor (PWR)
- BV-1 Commercial Operation - 1976
- BV-2 Commercial Operation - 1987
- 2652 MWt original licensed Rated Thermal Power (RTP)
- 2689 MWt Appendix K Margin Recovery - 2001
- 2900 MWt Extended Power Uprate (EPU) - pending

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BVPS Progress Timeline – Leading up to EPU

1998

FENOC Established (Dec)

1999

Beaver Valley Transferred from Duquesne Light to FirstEnergy (Dec)

2000

Full Potential Program Initiated

2001

Leading Edge Flow Meter Modification 1.4% (Oct)

2002

2003

BV1 HP Turbine Installed

2004

EPU LAR submittal (Oct)

Conversion to Westinghouse Robust Fuel Assembly Design (Nov)

2005

2006

Unit 1 Refueling Outage (Feb - April)

Unit 1 Steam Generator and Rx Vessel Head Replacement (Feb – Apr)

-Containment Conversion
- Rewind of Main Unit Generator
-Power Uprate Preparations (Feb – Apr)

Unit 2 Refueling Outage (Oct)

C01

Beaver Valley Peer Units - Power Uprates

Plant	Uprated NSSS Power Level (MWt)
Beaver Valley Units 1 & 2	**2910**
North Anna Units 1 & 2	**2905**
V. C. Summer	**2912**
Shearon Harris	**2912**
Vandellos	**2954**
ASCO Units 1 & 2	**2952**

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Oversight

- FENOC senior management involvement
- Oversight of the engineering and licensing process
  - Engineering Assessment Board
  - On-site Safety Review Committee
  - Nuclear Oversight (QA)
  - Corporate Nuclear Review Board
  - Independent Assessments

Overview

Pete Sena
Director, Site Engineering

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Overview - Agenda

- Preparations for Uprate
- General Criteria
- Project Team
- Technical Reviews

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Preparations for Uprate

To Position BVPS Units for EPU:

Supporting Submittals Completed:

- **New Fuel Storage Rack Enrichment Limit Increase**
- **Positive Moderator Temperature Coefficient**
- **Accumulator and RWST Increased Boron Concentration**
- **Selective implementation of AST**
- **Minimum Decay Time Before Fuel Movement**
- **Relaxed Axial Offset Control (RAOC)**

Replacement Steam Generators (RSG) BVPS-1

Containment Conversion

Large Break Best Estimate Loss-of-Coolant Accident (BELOCA) Methodology

Extended Power Uprate (EPU) - Pending

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General Criteria

- Key Elements
  - Extended Power Uprate (EPU)
    - Containment Qualified in Containment Conversion submittal
    - LOCA analysis performed using BELOCA methodology
  - Containment Conversion
    - Analyses conservatively performed at EPU conditions
  - BELOCA
    - License methodology for BVPS
    - Results included containment conversion

General Criteria

- Consistent approach with other power uprates
- Followed current licensing basis unless specifically identified
- Used BVPS analytical methodologies unless specifically identified
- No new industry (unlicensed) methodologies

Project Team

- FENOC / BVPS
  - Overall project management
  - Review and approval of inputs
  - Proper interfacing of Information
  - Procedure / Training / Simulator updates
- Westinghouse
- Stone and Webster
- Siemens Westinghouse
- Other vendors

Technical Reviews

- Rigorous owners acceptance reviews of vendor outputs
  - Acceptance reviews proceduralized
  - Challenge meetings
  - Engineering reviews to verify correct implementation
- Supported NRC Staff Audit reviews in the areas of
  - Probabilistic Risk Assessment
  - Safety Analysis
  - Radiological Assessment

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Plant Changes

Mark Manoleras
(Manager, Design Engineering)

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Plant Changes - Agenda

- Plant Modifications
- Electrical System Summary
- Use of Operating Experience

Plant Modifications

- Replacement of charging/safety injection pump rotating assemblies
- Conversion from a sub-atmospheric to an atmospheric containment design
  - Installation of fast acting feedwater isolation valves (Unit 1)
  - Installation of auxiliary feedwater cavitating venturies (Unit 1)
  - Addition of reactor cavity drainage port
  - Elimination of Quench Spray Cutback (Unit 1)
- Replacement of Steam Generators (Unit 1)

Plant Modifications

- Replace high pressure turbine with all-reaction design
- Install stakes in main condenser (Unit 2)
- Modify cooling tower fill (Unit 2)
- Raise set-pressure of moisture separator reheater relief valves

Plant Modifications

- Increase Cv of main feedwater control valves
- Replace Turbine Generator (T/G) rotor and rewind stator (Unit 1)
- Modify heater drain control valves
- Instrument replacements for higher flow range

Electrical System Summary

- Initial electrical design is robust
- BV-2 Main Transformer cooling upgraded
- Iso-phase bus duct – material condition upgrade
- Operating limits on grid voltage and reactive load established to protect post-trip voltage on busses
- Grid can accommodate a Beaver Valley trip from EPU condition
- 4 hour station blackout coping capability is unaffected

Industry OE

- Vibration issues
- Turbine rubs
- Turbine control – valves wide open
- Isophase bus duct air flow and cooling
- Transformer cooling
- Power measurement

Rx Fuel and Core Design

A. R. Burger
(Supervisor, Core Design & Physics Support)

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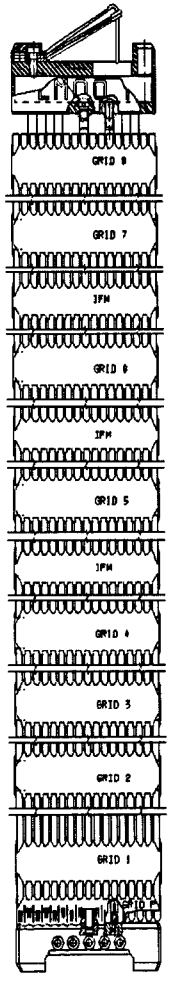
Fuel Design

- Robust Fuel Assembly (RFA)
  - 17 X 17 assembly
  - 2.6% enriched blankets (6 inches)
  - 0.374″ OD ZIRLO™ Clad
  - 463 kgU
- Integral Fuel Burnable Absorber (IFBA)
- Intermediate Flow Mixing (IFM) Grids
- 6 cycles of operating history



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Fuel Design

- IFMs provide increased DNB margin and utilize WRB-2M correlation
- RFA design provides increased resistance to grid-to-rod fretting fuel failures
- Increased guide tube thickness provides margin for Incomplete Rod Insertion (IRI)

Core Design

- Conceptual core design models for up-rated conditions
- Equilibrium cycle burnups increase from 18,800 MWD/MTU to 20,200 MWD/MTU
- Increased average Linear Heat Rate (LHR) - 5.28 to 5.69 kw/ft with EPU
- Peaking factors remain at 2.4 for Fq and 1.62 for FNΔH
- increase in feed batch size from 60 to 64 fuel assemblies to accommodate uprate
- Continued use of low-leakage loading pattern

Core Design

- No change in maximum enrichment
- No appreciable change in flux profile
- No transition core penalty - both units operating with RFA fuel design
- Relaxed Axial Offset Control (RAOC) provides increased operating flexibility compared to Constant Axial Offset Control (CAOC)

Safety Analysis

Ken Frederick
(Nuclear Safety Analyst)

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Safety Analysis Objectives

- Demonstrate compliance with regulatory limits and acceptance criteria

- To show that BVPS will operate with adequate safety margins at EPU conditions

Safety Analysis - Agenda

- BVPS EPU Design Parameters
- Safety/Control Setpoint Changes
- Safety Analysis Methodologies
- Non-LOCA Events
- LBLOCA
- SBLOCA
- Post LOCA Long Term Cooling / Boron Precipitation
- Containment/NPSH/Overpressure
- Dose Analysis

BVPS Power Uprate – Design Parameters

EPU Licensing Report	Rx Mass Flow E6 Lb/hr	Vessel Outlet Temp F	Vessel Outlet H Btu/lb	Vessel Inlet Temp F	Vessel Inlet H Btu/lb	Core Power Btu/hr	Power Ratio EPU / Current
Current Operation	99.5	610.8	628.97	541.60	536.83	9.168E09	NA
EPU Low Tavg (566.2 F)	101.1	603.9	618.84	528.50	520.98	9.894E09	1.08
EPU High Tavg (580.0 F)	99.3	617.0	638.35	543.10	538.67	9.898E09	1.08

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Safety Setpoint

- OPΔT
  - Reduced trip setpoint
  - Added filters to optimize operating margin
- OTΔT
  - Reduced trip setpoint
  - Added filters to optimize operating margin
- Other protection system changes
  - Low-Low S/G Level (BVPS-1)
  - Negative flux rate trip elimination
  - Containment pressure setpoints raised (CC)
  - RWST Level Low-Low (SI Recirc) setpoint lowered (CC)

Control System Setpoint Changes

- Pressurizer Level @ full power
- Steam dump system control setpoints
- Steam Generator level (BVPS-1)

Safety Analysis Methods

Method	EPU	Current
Large Break LOCA	BELOCA/WCOBRA-TRAC	BASH (App K)
Small Break LOCA	NOTRUMP	NOTRUMP
Non-LOCA	LOFTRAN VIPRE	LOFTRAN THINC
Control System Transients	LOFTRAN	LOFTRAN
Containment	MAAP-DBA	MAAP-DBA (LOCTIC pre-CC)
Dose Assessment	AST/ARCON 96	TID/RAMSDELL

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Non-LOCA Events

- Decrease in Heat Removal by Secondary System
  - Loss Of Electrical Load and/or Turbine Trip
  - Loss of Normal Feedwater
  - Loss of Offsite Power to the Station Auxiliaries
  - Major Rupture of a Main Feedwater Pipe
- Increase in Heat Removal by Secondary System
  - Excessive Load Increase Incident
  - Excessive Heat Removal Due to Feedwater System Malfunctions
  - Steam System Piping Failure at Full Power
  - Major Rupture of a Main Steam Pipe (HZP)

Non-LOCA Events

- Reactivity and Power Distribution Anomalies
  - Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition
  - Uncontrolled RCCA Bank Withdrawal at Power
  - RCCA Misalignment
  - Uncontrolled Boron Dilution
  - Rupture of a Control Rod Drive Mechanism Housing- RCCA Ejection
- Decrease in Reactor Coolant System Flowrate
  - Complete Loss of Forced Reactor Coolant Flow
  - Partial Loss of Forced Reactor Coolant Flow
  - Single Reactor Coolant Pump Locked Rotor

Non-LOCA Events

- Decrease in Reactor Coolant Inventory
  - Accidental Depressurization of the Reactor Coolant System
- Increase in Reactor Coolant Inventory
  - Spurious Operation of the Safety Injection System at Power

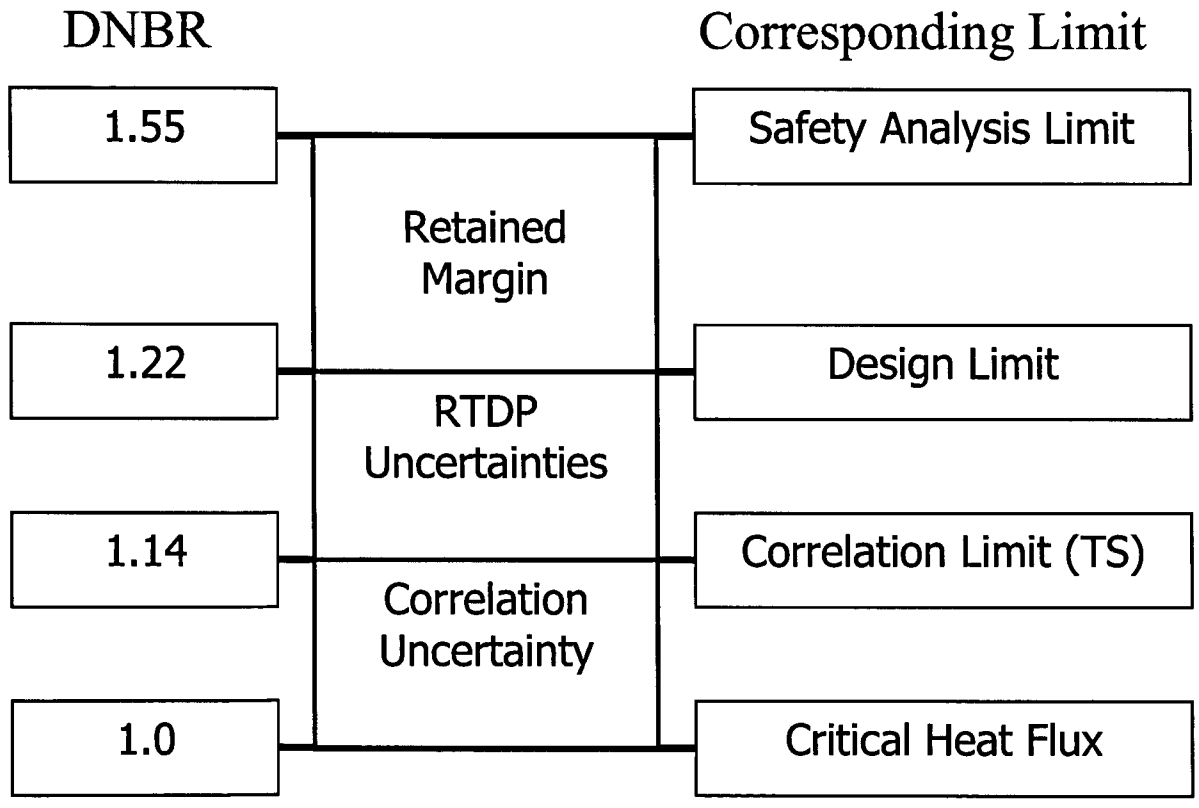
Non-LOCA Acceptance Criteria

- Most Non-LOCA events are categorized as ANS Condition II for which the acceptance criteria are:
  - The critical heat flux is not exceeded (the calculated minimum DNBR does not go below the limit value at any time during the transient)
  - Peak heat generation rate remains within acceptable limits to prevent fuel centerline melt
  - Pressure in the RCS and main steam systems should be maintained below 110% of the design pressures
  - The event should not generate a more serious plant condition without other faults occurring independently

Non-LOCA DNBR Analysis

- DNBR is calculated using approved correlations
  - WRB-1,WRB-2M,W-3 used as applicable based on fuel type and RCS conditions
- Revised Thermal Design Procedure (RTDP) is used for most analyses
  - Combines uncertainties on RCS power, flow, temperature, and pressure into DNBR penalties by statistical methodology
- DNBR margin is retained in limits
  - For BVPS, 21.2% margin is retained between safety analysis limits and design limits for events using WRB-2M
  - Retained margin allows for greater core design flexibility during reload process

Non-LOCA DNBR Margin



WRB-2M DNBR LIMITS

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Non-LOCA DNBR Results

DNBR Limited Events				
Event	DNBR Correlation	DNBR Limit	BVPS-1 DNBR	BVPS-2 DNBR
RCCA Bank Withdrawal from Subcritical	W-3,WRB-1	1.65, 1.45	1.83, 2.12	1.83, 2.12
RCCA Bank Withdrawal at Power	WRB-2M	1.55	1.57	1.58
RCCA Misalignment	WRB-2M	1.55	(1)	(1)
Loss of Load	WRB-2M	1.55	2.23	1.83
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	 WRB-2M WRB-2M	 1.55 1.55	 1.75 1.67	 1.96 1.66
RCS Depressurization	WRB-2M	1.55	1.62	1.64
Main Steam Pipe Rupture (HFP)(2)	WRB-2M	1.55	2.56	2.56
Main Steam Pipe Rupture (HZP)(2)	W-3	1.61	2.41	1.83
Partial Loss of Flow	WRB-2M	1.55	2.25	2.25
Complete Loss of Flow	WRB-2M	1.55	1.64	1.64

(1) No DNBR Results-Analysis uses peaking factor limits for evaluation
(2) Condition IV event evaluated with Condition II limits

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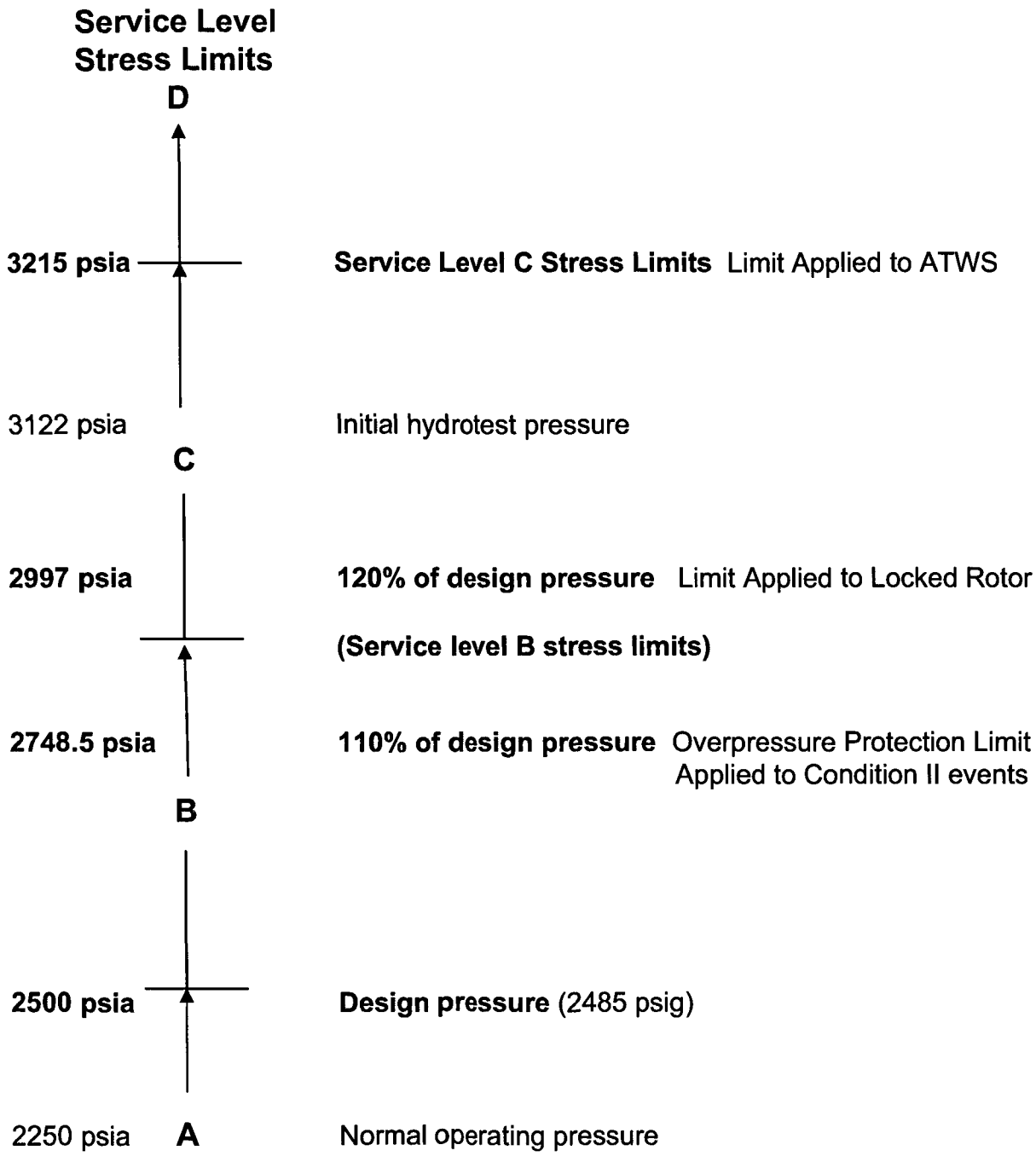
Service Level
Stress Limits
D
3215 psia
Service Level C Stress Limits Limit Applied to ATWS
3122 psia
Initial hydrotest pressure
C
2997 psia
120% of design pressure Limit Applied to Locked Rotor
(Service level B stress limits)
2748.5 psia
110% of design pressure Overpressure Protection Limit
Applied to Condition II events
B
2500 psia
Design pressure (2485 psig)
2250 psia
A
Normal operating pressure

Non-LOCA Pressure Results

Limiting Overpressure Events						
Event	Primary Pressure Limit (Psia)	BVPS-1 Peak Primary Pressure (Psia)	BVPS-2 Peak Primary Pressure (Psia)	Secondary Pressure Limit (Psia)	BVPS-1 Peak Secondary Pressure (Psia)	BVPS-2 Peak Secondary Pressure (Psia)
Loss of Load	2748.5	2747	2746	1208.5	1192	1191
Feedwater System Malfunctions	2748.5	2357	2353	1208.5	1124	1141
Partial Loss of RCS Flow	2748.5	2374	2361	1208.5	989	995
Complete Loss of RCS Flow	2748.5	2504	2503	1208.5	993	1003
Locked Rotor	2997	2797	2825	-	-	-
ATWS	3215	3060	2900	-	-	-

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Non-LOCA Other Results

Pressurizer Filling Events			
Event	Pressurizer Water Volume Limit (ft^3)	BVPS-1 Peak Pressurizer Water Volume (ft^3)	BVPS-2 Peak Pressurizer Water Volume (ft^3)
Loss of Normal Feedwater	1458	1384	1193
Loss of AC	1458	1224	1194
Spurious Safety Injection	1458	Pressurizer Fills	Pressurizer Fills
Margin to Hot Leg Saturation Event			
Event	Margin to Hot Leg Boiling Limit (°F)	BVPS-1 Margin to Hot Leg Boiling (°F)	BVPS-2 Margin to Hot Leg Boiling (°F)
Feedline Break	0 (No boiling)	14.4	36
Maximum Fuel Stored Energy Event			
Event	Max Fuel Stored Energy Limit (Btu/Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)
RCCA Ejection	360	326.8	326.8

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Non-LOCA Loss of Load Transient

- This event produces the highest primary and secondary pressures of the Condition II events
- Results from either a loss of electrical load without direct turbine trip or a turbine trip
- Protection for this event provided by:
  - Hi Pressurizer pressure trip
  - High Pressurizer water level trip (not credited)
  - Overtemperature ΔT trip
  - Low-low S/G trip if feedwater is lost
  - Reactor trip on turbine trip (not credited)

Non-LOCA Loss of Load Transient

- Two cases are performed:
  - DNBR with pressure control
  - Pressure case with no pressure control
- Conservatisms in analysis
  - Inputs biased for worst results
    - Pressurizer pressure and level
    - RCS power, flow, and temperatures
    - Reactivity feedback
    - Manual rod control
  - No credit for condenser steam dumps or atmospheric relief valves
  - No credit for Pressurizer spray or PORVs for pressure case
  - Maximum setpoint tolerance for Pressurizer safety valves
  - Main feedwater lost at time of turbine trip
  - Safety valve performance model includes opening delays for loop seal purge, valve opening time, and setpoint shifts

Non-LOCA Loss of Load Transient

Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	8.2

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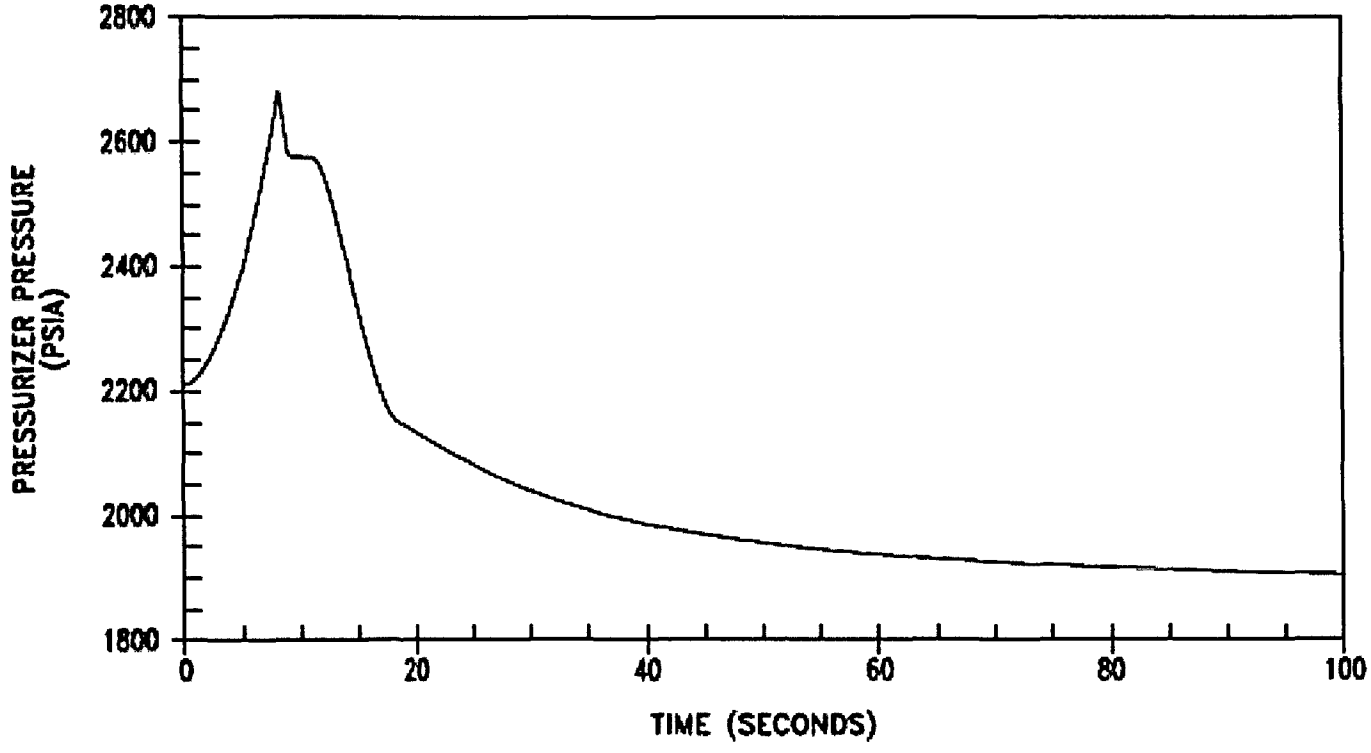
Non-LOCA Loss of Load Transient



BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure versus Time

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Non-LOCA Loss of Load Transient

Comparison of Peak RCS Pressure following Loss of Load Event		
	BVPS-1	**BVPS-2**
Pre-EPU Peak RCS Pressure psia	**2732.7**	**2747.5**
EPU Peak RCS Pressure psia	**2747.3**	**2746.2**

- A realistic analysis which credits all control systems show a peak pressure of 2340 psia and no safety valves lift

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Non-LOCA Rod Withdrawal at Power

- This event produces the most limiting results for DNBR
- Event initiated by malfunction of rod control or operator error
- Reactor protection provided by:
  - Power range high flux trip
  - Overtemperature ΔT trip
  - Overpower ΔT trip
  - High Pressurizer pressure trip
  - High Pressurizer water level trip
  - Positive neutron flux rate trip
- Rod withdrawal blocks also present but not credited

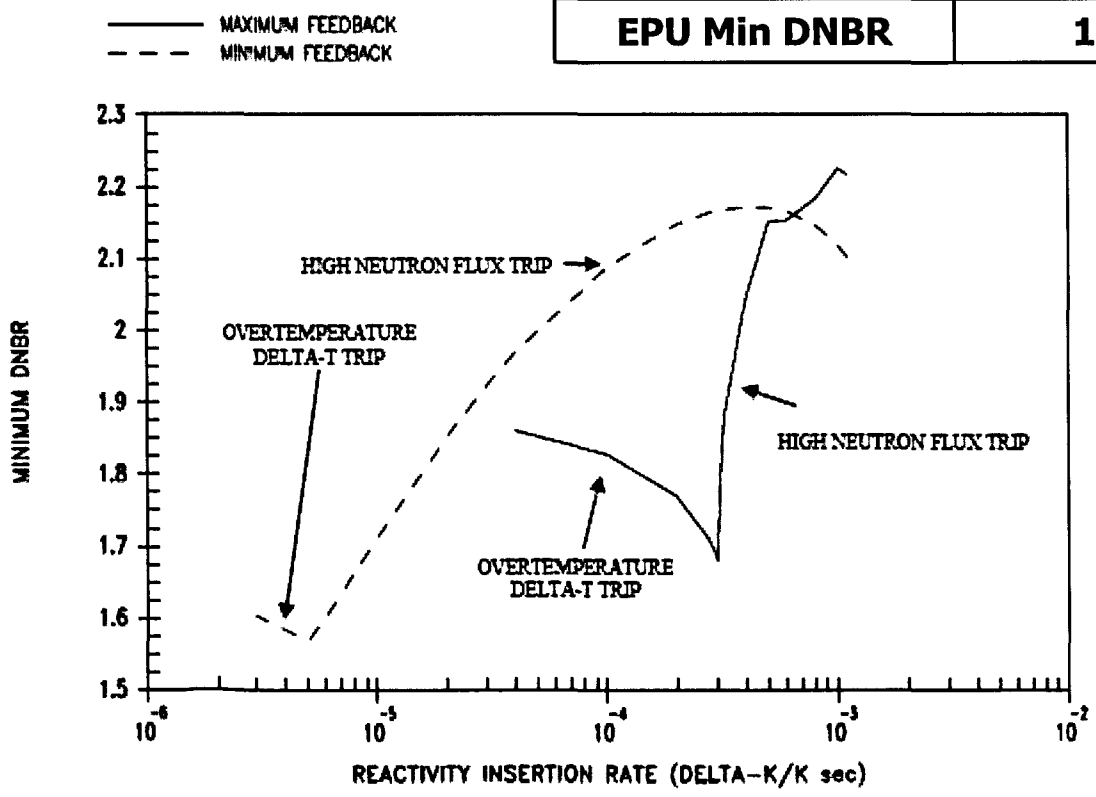
Non-LOCA Rod Withdrawal at Power

- Many cases are analyzed over a range of reactivity insertion rates and initial power levels of 10%, 60% and 100%
- Conservatisms included in the analysis:
  - Initial condition uncertainties on reactor power, temperature, flow and pressure
  - Conservative values of reactivity feedback
  - Maximum adverse uncertainties is assumed on all trip setpoints
  - Highest worth RCCA stuck out of core
  - Maximum positive reactivity insertion rate assumed is greater than BVPS design
  - Auto rod withdrawal has been eliminated

Non-LOCA Rod Withdrawal at Power

- Results demonstrate protection is adequate over range of reactivity rates assumed

Comparison of Minimum DNBR following Rod Withdrawal at Power	
Pre-EPU Min DNBR	**1.57**
EPU Min DNBR	**1.57**



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Non-LOCA Spurious Safety Injection

- Spurious Safety Injection is a Condition II event
- Event is initiated by a malfunction or error which initiates a safety injection signal
- SI signal generates a reactor trip and turbine trip
- DNBR is not challenged due to addition of cold water
- Primary concern is pressurizer overfill and water discharge through safety valves

Non-LOCA Spurious Safety Injection

- Conservatisms included in analysis:
  - Maximum core power plus uncertainty
  - Initial pressure, temperature and flow conditions with uncertainties biased for worst results
  - Maximum initial pressurizer level plus uncertainties
  - Performed with and without pressurizer heaters
  - Two HHSI pumps start at maximum flow with uncertainties
  - PORVs not credited for PSV operability case
  - Colder water entering pressurizer is assumed to instantly mix with hot water volume (minimizes PZR temperature)
- Event mitigation provided by operator actions to either open PORV or shutdown HHSI pumps

Non-LOCA Spurious Safety Injection

- Pressurizer predicted to overfill prior to operator action at ten minutes
- Analysis used to generate water discharge parameters (# cycles, temperature, flow) for PORVs and Safety Valves
- PSV evaluation used WCAP 11677 methodology based on EPRI safety valve test results
- PORVs have qualified low pressure close signal
- Discharge piping analyzed to show design limits are met with a water discharge.

Non-LOCA Spurious Safety Injection

- Analyses conclude that PSVs can pass water without damage
- PORVs also capable of discharging water without damage
- PORVs have qualified signal to close; do not need to rely on block valve closure
- Spurious SI event will not propagate to Condition III event

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Non-LOCA Conclusions

- DNBR limits contain margin between safety analysis limits design limits to allow for core design flexibility
- Conservatism in peak pressure limits and analysis inputs allow for maintaining margins in operating limits
- All acceptance criteria for Condition II,III,IV Non-LOCA events are met at EPU conditions

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Safety Analysis – Large Break LOCA

- EPU analysis performed using Westinghouse 1996 BELOCA methodology using WCOBRA/TRAC
- PCT margin gained from methodology change, increase in containment operating pressure, and minimum accumulator pressure partially offsets increase in power from EPU
- Results indicate acceptance limits met with margin

Large Break LOCA - Results

Parameter	Current (App K)	EPU (BELOCA)	Limit
Unit 1 Peak Clad Temperature	1996 °F	2021 °F	<2200 °F
Unit 2 Peak Clad Temperature	1908 °F	1976 °F	<2200 °F
Unit 1 Maximum Transient Local Cladding Oxidation	10.2 %	8.77 %	<17 %
Unit 2 Maximum Transient Local Cladding Oxidation	8.9 %	6.7 %	<17 %
Unit 1 Maximum Hydrogen Generation	0.91 %	0.98 %	<1%
Unit 2 Maximum Hydrogen Generation	0.58 %	0.91 %	<1%

Safety Analysis -SBLOCA

- Analysis performed utilizing NRC approved Evaluation Model (EM) with NOTRUMP
- PCT margin gained through plant modifications:
  - Increase in Safety Injection flows
    - New higher runout capacity HHSI pumps
    - Improved instrumentation => lower uncertainties
  - Increase in minimum SI Accumulator pressure

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SBLOCA – NRC Questions

- Coarseness of break spectrum
  - (Integer break sizes, e.g. 2″,3″,4″)
- Loop seal clearing assumptions
  - NOTRUMP licensed for loop seal clearing on broken loop only
- Cladding oxidation should include pre-transient oxidation
- Operator actions to cool down and depressurize for smaller breaks need to be performed to refill reactor vessel in a timely manner

SBLOCA – NRC Questions

- BVPS analyses were re-run to address NRC issues
  - Break sizes were investigated at 0.25" increments
  - Allowance for loop seal clearing on intact loops was removed
  - Burnup studies for cladding oxidation were performed and shown to meet limit with pre-transient oxidation included
- Revised analyses incorporate increased accumulator pressure for improved results
- Simulator studies confirm EOP ES-1.2 cooldown and depressurization commenced within 30 minutes
- Revised analyses demonstrate acceptable results with adequate margin

Small Break LOCA - Results

Parameter	Current	EPU	Limit
Unit 1 Peak Clad Temperature	1902 °F	1895°F	<2200 °F
Unit 2 Peak Clad Temperature	1902 °F	1917 °F	<2200 °F
Unit 1 Maximum Transient Local Cladding Oxidation	14.47 %	11.07 %	<17 %
Unit 2 Maximum Transient Local Cladding Oxidation	14.47 %	13.42 %	<17 %
Unit 1 Maximum Hydrogen Generation	0.72 %	0.64 %	<1%
Unit 2 Maximum Hydrogen Generation	0.72 %	0.77 %	<1%

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Post-LOCA Long Term Cooling

- Analyses performed to demonstrate:
  - Boron concentration in core can be maintained below precipitation limits (switchover time)
  - Safety injection flows in all alignments (cold leg and simultaneous hot and cold leg injection) are adequate to flush the core and remove decay heat

Post-LOCA Long Term Cooling

- The NRC identified four items to be addressed for post-LOCA long term cooling boric acid analyses
  - Core voiding must be considered by reducing the mixing volume accordingly
  - Time-based Mixing Volume / System Effects must be considered
  - BA Solubility limit must be justified, particularly if sump additives or over-atmospheric pressure is credited
  - Appendix K decay heat must be used
- BVPS long term cooling calculations were re-done to address these items

Long Term Cooling -Analysis

- Core voiding must be considered by reducing the mixing volume accordingly
  - Core voiding was calculated used modified Yeh Correlation
  - Voiding calculations were benchmarked against Large Break and Small Break ECCS code calculations (WCOBRA/TRAC and NOTRUMP)
- Time-based Mixing Volume / System Effects must be considered
  - Time-based liquid volume was calculated using core voiding predictions
  - Liquid volume was benchmarked against Large Break and Small Break ECCS code calculations
  - Loop pressure drop effect was evaluated using large break ECCS code calculations
- BA Solubility limit must be justified, particularly if sump additives or over-atmospheric pressure is credited
  - The beneficial effect of sump additives on boric acid solubility was developed but not credited (Precipitation limit increases to from 29% to ~48% with NaOH additive)
  - Atmospheric pressure solubility limit was used in all calculations
- NRC considers Appendix K decay heat a requirement
  - Appendix K decay heat was used in all calculations.

Long Term Cooling -Analysis

- Additional issue identified in Draft SER
- For SBLOCA scenarios which do not refill, capability to cool down and depressurize in <6 hours needs to be demonstrated
- Preliminary analyses indicate sufficient heat removal capacity is available to meet required times
- Discussions with staff indicate acceptable resolution of issue – FENOC will follow up with NRC to close the issue

Long Term Cooling Summary

- Post LOCA long term core cooling has been adequately addressed
- Results show the following for switchover time to hot leg injection:
  - BVPS-1 - 6.5 hours
  - BVPS-2 - 6 hours
- Emergency Operating Procedures require preparations be made to align to hot leg at:
  - BVPS-1 - 5.5 hours
  - BVPS-2 - 5 hours

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Containment Analysis

- Amendments have been approved to convert BVPS-1 and BVPS-2 to an atmospheric containment design (Containment Conversion)
- Containment Conversion analysis accounts for EPU conditions which primarily impacts:
  - LOCA M&E Releases
  - MSLB M&E Releases
- LBLOCA and MSLB M&E release calculations use previously approved Westinghouse methodologies

Containment Analysis

- Containment integrity analyses utilize MAAP-DBA
  - New methodology recently approved by NRC for BVPS Containment Conversion Program
  - Similar to other approved codes (GOTHIC, COCO, etc)
  - Uses traditional heat transfer correlations (Tagami, Uchida)
  - Multiple node model used to capture water holdup for NPSH
- SBLOCA M&E releases use MAAP-DBA

Containment Analysis

- Containment will operate at slightly sub-atmospheric conditions
  - Prior to containment conversion 9 psia to 10.5 psia (air partial pressure)
  - Following containment conversion 12.8 psia to 14.2 psia

- Analysis credits plant modifications
  - Replacement Steam Generators (BVPS-1)
  - New feedwater isolation valves (BVPS-1)
  - AFW cavitating venturis (BVPS-1)
  - Reactor cavity drainage port
  - QS cutback elimination (BVPS-1)
  - Lowered RWST level setpoint for transfer to SI recirculation

Containment Analysis

- Containment Analysis acceptance criteria:
  - Containment Peak Pressure (LOCA and MSLB) < 45 psig design pressure
  - Containment pressure reduction of 50% of peak in 24 hours
  - NPSH for pumps which recirculate from sump exceeds required NPSH [Recirculation Spray (RS) and Low Head Safety Injection (LHSI)]
  - Minimum sump inventory is sufficient during pump start

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Containment Analysis - Results

- Peak Containment Pressures within Design (45 psig) for all accidents

	EPU Peak Pressure Results psig	Pre-EPU Peak Pressure Results psig
BVPS-1 LOCA	43.3	40.0
BVPS-1 MSLB	42.6	44.2
BVPS-2 LOCA	44.9	44.7
BVPS-2 MSLB	39.3	41.0

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Containment Analysis - Results

- Containment Pressure reduced to <1/2 Pa within 24 hours
- All NPSH requirements satisfied
- All equipment required to operate remains qualified for environmental conditions
- Piping and structures qualified for sump and atmosphere temperature profiles
- Minimum sump inventory sufficient for pump operation

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Containment Overpressure

- Containment Overpressure (COP) is required for BV-1 to support NPSH for Recirculation Spray pumps
  - COP credit is part of existing licensing basis for BVPS-1
  - COP continues to be credited for Containment Conversion / EPU
  - BVPS-2 does not need to credit COP due to differences in physical layout (pumps at ~13 feet lower elevation)

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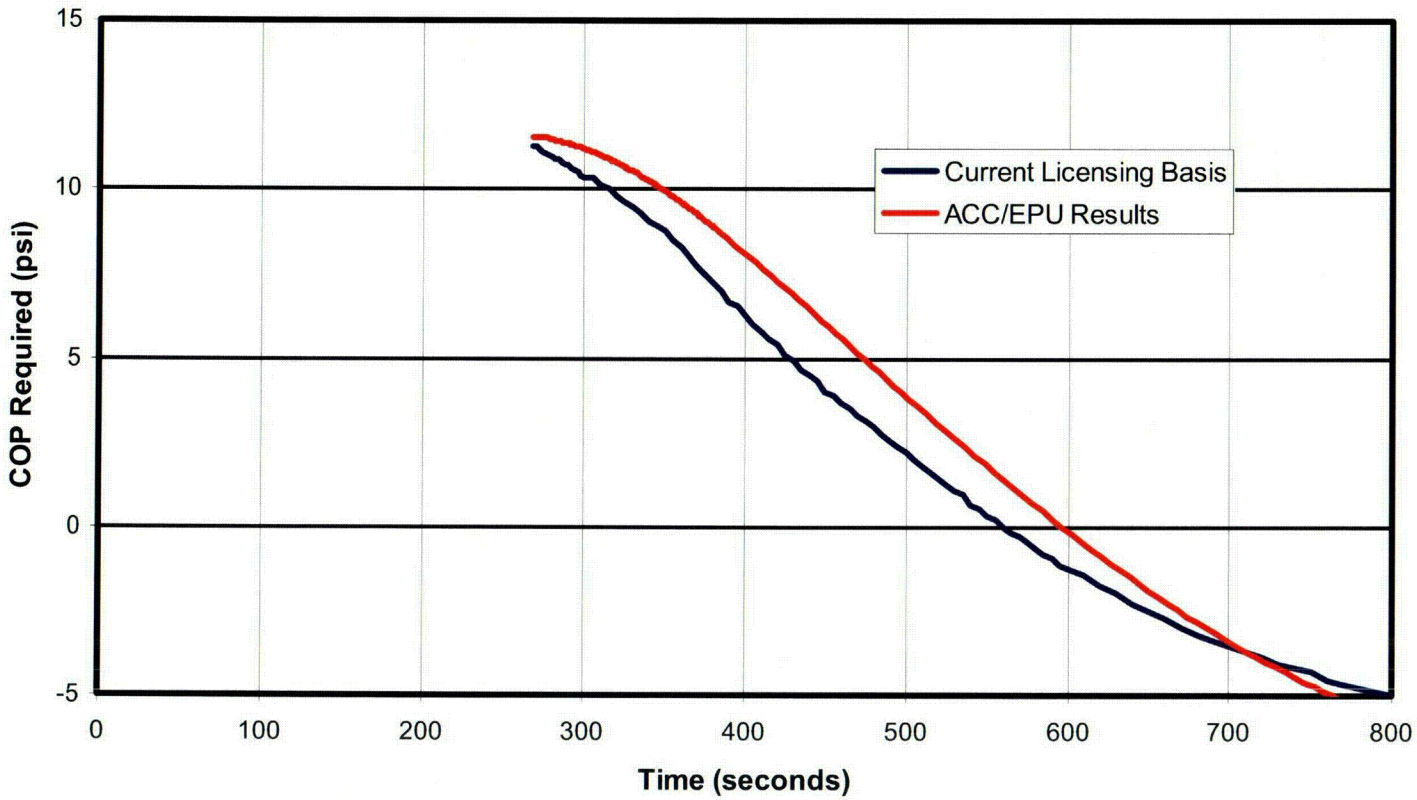
Containment Overpressure

- BVPS-1 Recirculation Spray System (RSS)
  - consists of four pumps and spray rings
  - automatically start within five minutes of a spray initiation signal (CIB)
  - draws water from the containment sump
- Due to early start time
  - sump level is relatively low
  - sump temperature high
  - NPSH availability is limited
- NPSH available decreases following pump start due to rapid depressurization of containment relative to sump temperature

COP Required for Inside RS Pump



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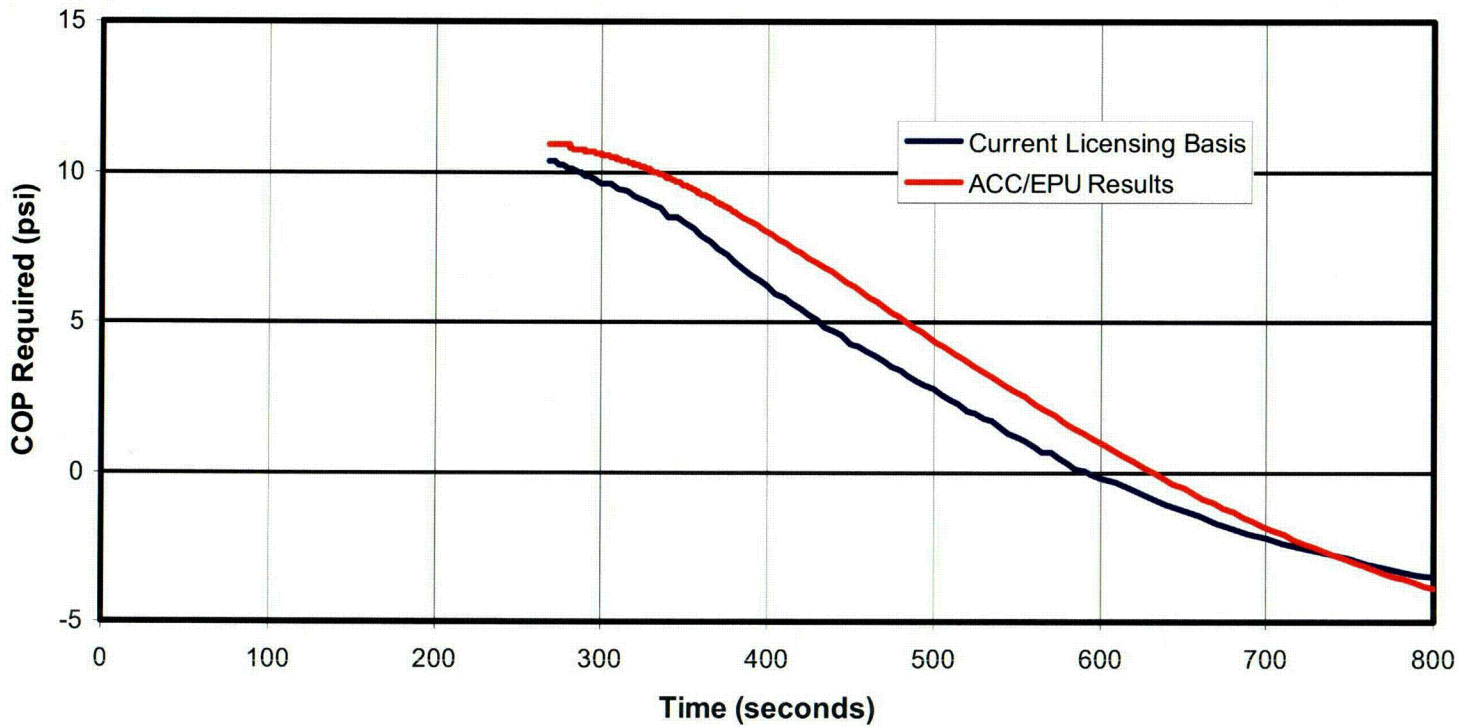
C02

COP Required for Outside RS Pump



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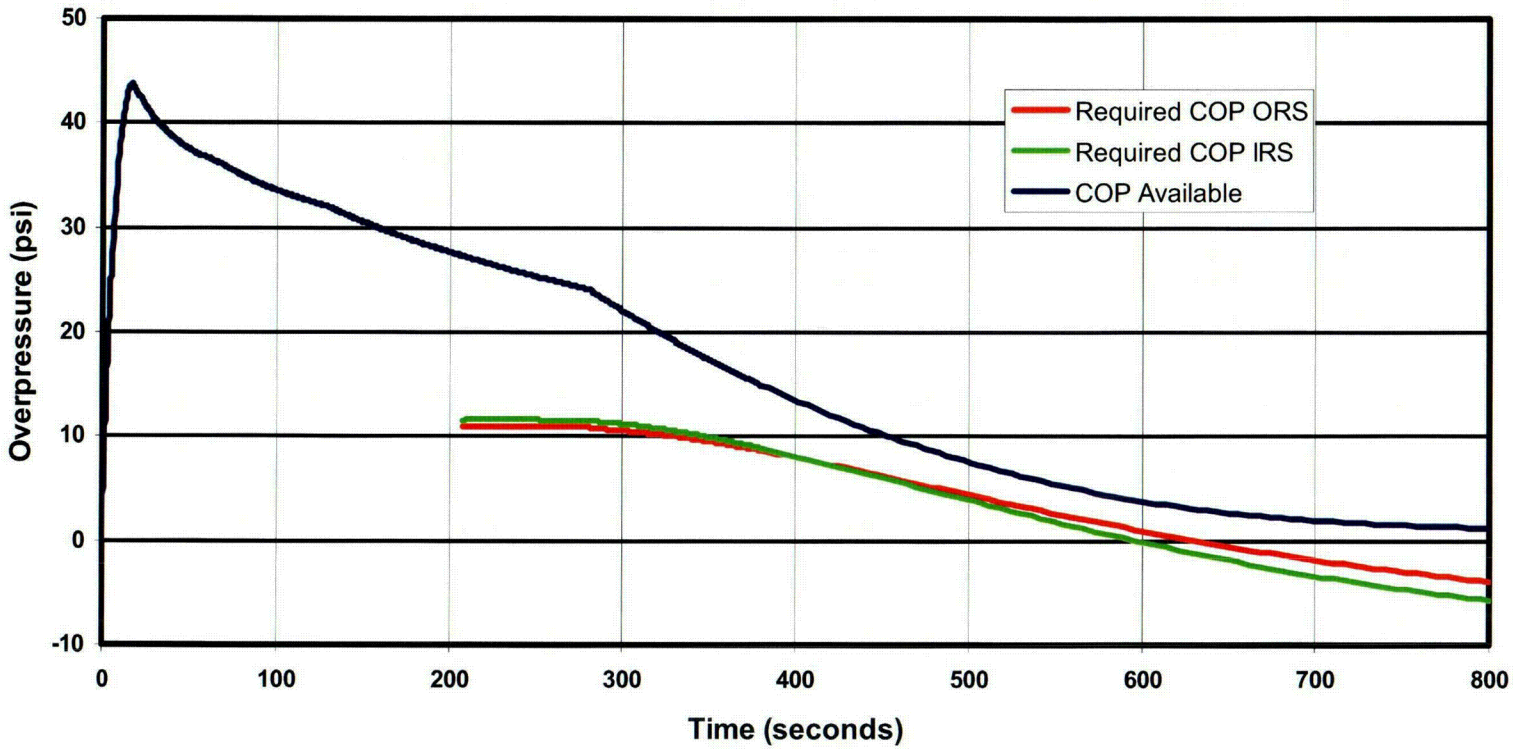
C03

Required and Available Overpressure



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C04

Containment Overpressure

- The previous curves are based on the limiting NPSH case and do not represent the bounding case in terms of COP time requirements
- Minimum heat removal cases are less limiting for NPSH margin but require COP for a longer period
- For all cases, COP is required for less than 20 minutes
- Based on testing completed on the model of RS pumps used at BVPS-1, the pumps are capable of operating at NPSH conditions below the standard definition of required NPSH (3% reduction in TDH) for a period of time exceeding the time of required COP

Containment Overpressure

- There is a low probability of losing containment isolation coincident with a LOCA (~1.0 E-8)
- The largest normally open piping penetrations which communicate directly with containment atmosphere are 2" diameter
- Loss of containment integrity is readily identifiable due to slightly sub-atmospheric operation
- Analyses have shown that failures of piping or isolation for lines which communicate directly with containment environment would not significantly effect NPSH
- The following plot shows the effect on the NPSH margin for containment openings of 1",2",3" diameter

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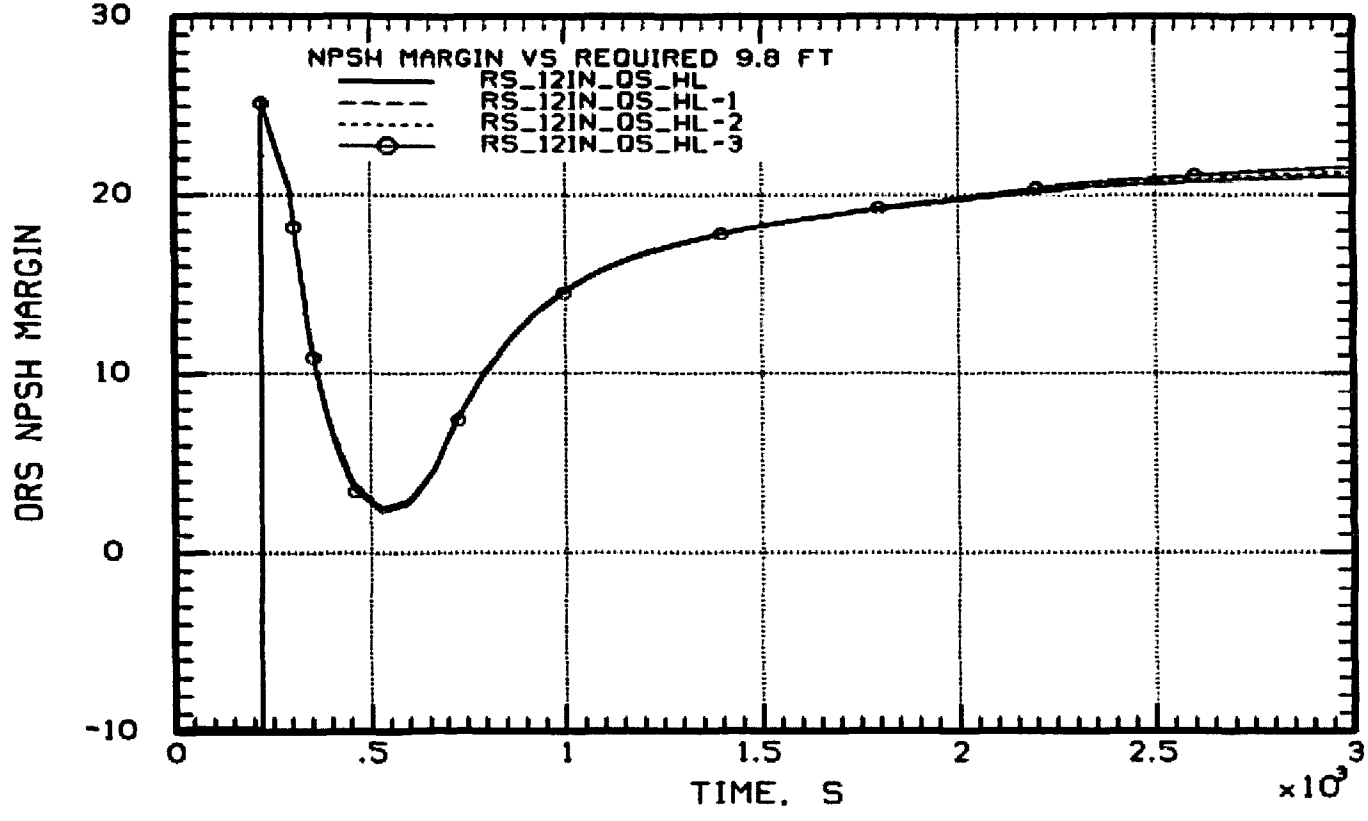
Containment Overpressure



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Containment Overpressure

- No operator actions are required or credited to maintain required COP
- Operators are trained to observe pump performance for signs of cavitation
- Modifications to eliminate need for COP are considered impractical or ineffective
  - Lowering of RS Pumps
  - Injecting additional cool water into RS pump suction
  - Restricting pump flow to lower required NPSH

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Containment Overpressure - Summary

- COP required for BVPS-1 RS pumps
- COP is part of current licensing basis for BVPS-1
- COP required for less than 20 minutes following pump start
- Type of RS pumps used at BVPS-1 have been successfully tested for operation below required NPSH
- The risk of losing COP is very low
- Modifications to eliminate need for COP are not practical

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Safety Analysis – Dose Assessment

- Application of Alternative Source Term (AST) consistent with RG 1.183
- Updated X/Qs with more recent meteorological data
- ARCON 96 methodology used for on-site X/Q values
- Control room tracer gas test completed and results incorporated into dose analyses
- BV-2 continues to use Alternate Repair Criteria, Accident Induced Leakage for MSLB
- Calculated doses for EPU are within requirements of 10CFR50.67 for off-site and control room

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Dose Assessment Results

Accident	EAB Dose (rem)	LPZ Dose (rem)	Offsite Limit	CR Dose (5 rem limit)
LOCA	14	2.5	25	2.0
CREA	3.1	1.5	6.3	1.3
MSLB (PIS)BV-1	0.08	0.01	25	0.5
MSLB (CIS) BV-1	0.11	0.04	2.5	0.66
MSLB (PIS)BV-2	0.4	0.1	25	0.2
MSLB (CIS) BV-2	2.5*	0.7	2.5	0.6
SGTR (PIS)	2.27	0.14	25	1.95
SGTR (CIS)	0.93	0.06	2.5	0.67
LRA	2.0	0.33	2.5	2.2
LACP	**	**	2.5	**
FHA	2.43	0.12	6.3	2.36
SLB	0.23	0.012	2.5	0.7

* Alternate Repair Criteria **bounded by LRA

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Safety Analysis Conclusions

- All applicable acceptance criteria are met at EPU conditions
- Beneficial plant modifications have been made to maintain safety margins at EPU conditions

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Materials & Rx Vessel

Dennis Weakland
(Fleet Materials)

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Materials and Rx Vessel

- Reactor Coolant Pressure Boundary
  - Materials of Construction
  - Integrity Programs
- Alloy 600 Management
- Reactor Vessel Integrity
  - Pressurized Thermal Shock
  - Upper Shelf Energy

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RCS Materials

- Rx Vessel, SG and Pressurizer are carbon steel with Stainless Steel Clad
  - Penetrations
    - Stainless Steel
    - Alloy 600
- RCS Primary Loop Piping - Cast SS
- Balance of RCS Piping – SS
- Piping to vessel and component welds
  - Stainless Steel
  - Alloy 600 (82/182)

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RCS Materials

Material Integrity Programs

- *Steam Generator Integrity Program*
- *Alloy 600 Program*
- *Boric Acid Program*
- *Reactor Vessel Integrity Program*
- *Materials Degradation Management Program*

These programs address specific RCS Integrity Issues and supplement the other Operations and Systems based Integrity programs

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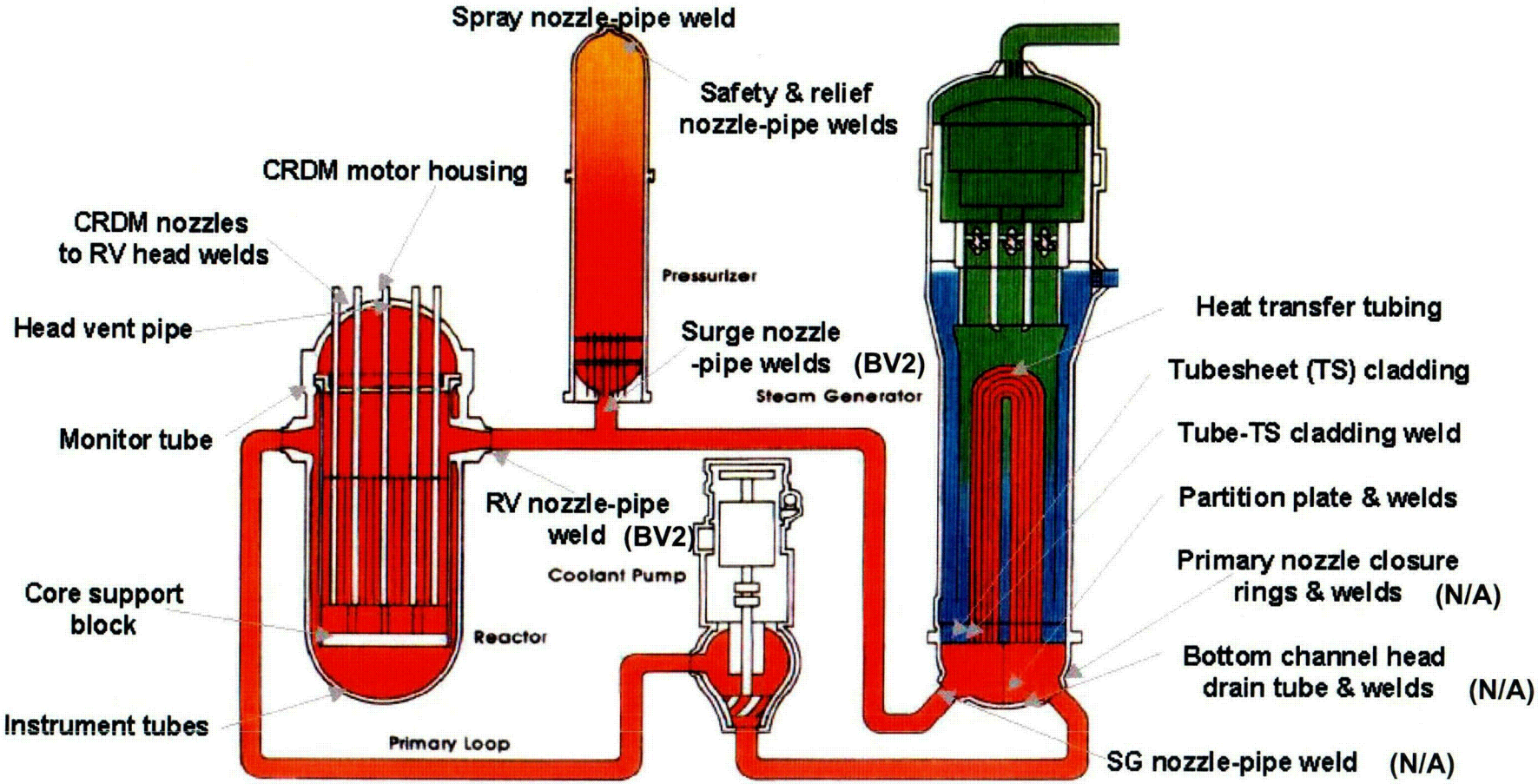
RCS Materials – Alloy 600 Program



NOTE: SG components are managed under the Steam Generator Management Program

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C05

BV-2 Head Inspection

- 2R10 (Fall 2003) Visual and Volumetric Inspection
  - Bare Metal Visual CDRMs and Head
    - No Degradation
  - Volumetric of CDRM penetrations
    - No Degradation
  - Eddy Current Exam of Vent line and weld
    - No Degradation
- 2R11 (Spring 2005) Visual Inspection
  - Bare Metal Visual CDRMs and Head
    - No Degradation

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RCS Materials – Alloy 600 Program

Mitigation and Strategy

- BV Unit 1
  - RV Head and Steam Generators
    - Replaced (1R17, Spring 2006)
  - Pressurizer Nozzles
    - Weld Overlay (1R18, Fall 2007)
  - Remaining Alloy 600 will be limited
    - BMNs
    - RV Internals

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RCS Materials – Alloy 600 Program

Mitigation and Strategy

- Beaver Valley Unit 2
  - Pressurizer Nozzles including Surge
    - Weld Overlay (2R12, Fall 2006)
  - Main Loop to Vessel Welds
    - Mitigation approach under review
  - Remaining Alloy 600
    - BMNs
    - RV Internals
    - SG Tubing and Internal Components
    - RV CRDM

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RCS Materials - Rx Vessel Integrity

- Reactor Vessel Materials Assessment Summary:
  - Fluence impact due to:
    - Uprate
    - Improved Capacity Factor
  - Surveillance schedule – No change BV 1 or BV 2
  - Upper Shelf Energy (USE) – > 50 ft-lbs for BV 1 and BV 2
  - PTS screening criteria (RTndt) - <270°F for BV 1 and BV 2
    - Both BV 1 and BV 2 are Plate Limited Plants
  - Applicability of heatup / cool down curves (Appendix G)
    - BV 1 Applicability adjusted for increase in fluence
    - BV 2 Analysis of record already addressed increase in fluence
    - Both will be revised through the PTLR Process
  - Operating pressure / temperature limits relative to ERG – No Changes for BV 1 or BV 2

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RCS Materials – RV EFPY

- Fluence – EFPY Relationship in EPULAR
  - *BV 1*
    - *WCAP 15571 Capsule Y – 28 EFPY*
      - *Fluence - 3.54 E19 n/cm²*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% Uprate, did not address 8% Uprate*
    - *EPULR Table 4.1.2-1A – 27.44 EFPY*
      - *Fluence - 3.54 E19 n/cm²*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% Uprate from WCAP, 8% Uprate in June 2003*
  - *BV 2*
    - *WCAP 15575 Capsule Y – 32 EFPY*
      - *Fluence - 3.85 E19 n/cm²*
      - *RT_{PTS} – 149 °F*
      - *Assumed 1.4% in 2001, 8% Uprate in June 2003*

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RCS Materials – RV EFPY

- Fluence – Current EFPY Projections
  - *BV 1*
    - *Current Projection – 30.5 EFPY*
      - *Fluence - 3.54 E19 n/cm^2*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% 2001 (WCAP 15571), 8% Uprate in June 2006*
      - *Capacity Factor of 98%*
  - *BV 2*
    - *Current Projection, WCAP 16527 – 36 EFPY*
      - *Fluence – 4.113 E19 n/cm^2*
      - *RT_{PTS} – 149 °F*
      - *Assumed 1.4% in 2001, 8% Uprate in June 2006*
      - *Capacity Factor of 98%*

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RCS Materials - Summary

- Materials Considerations
  - *Temperature Assessment*
    - *No Programmatic Impact on Alloy 600 Program*
    - *No programmatic impact on Steam Generator Program*
  - *Fluence Assessment*
    - *No significant impact on Reactor Vessel Integrity*
    - *No significant impact on Reactor Vessel Internals*
- *These small changes in material response to these conditions is addressed through the Materials Management Programs*

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Mechanical Impacts

Mike Testa
(EPU Project Manager)

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Mechanical Impacts – Agenda

- Steam Generator
- BOP Heat Exchangers
- Vibration Monitoring Program
- Cooling Water Systems
- Flow Accelerated Corrosion

Steam Generator Vibration

- Thermal-Hydraulic Analysis w/Athos
- Vibration potential in U-Bend & Tube Bundle Entrance
- Potential tube vibration mechanisms
  - Fluidelastic instability
  - Vortex shedding
  - Random turbulence excitation
- Tube wear (U-Bend region)

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Tube Bundle Region

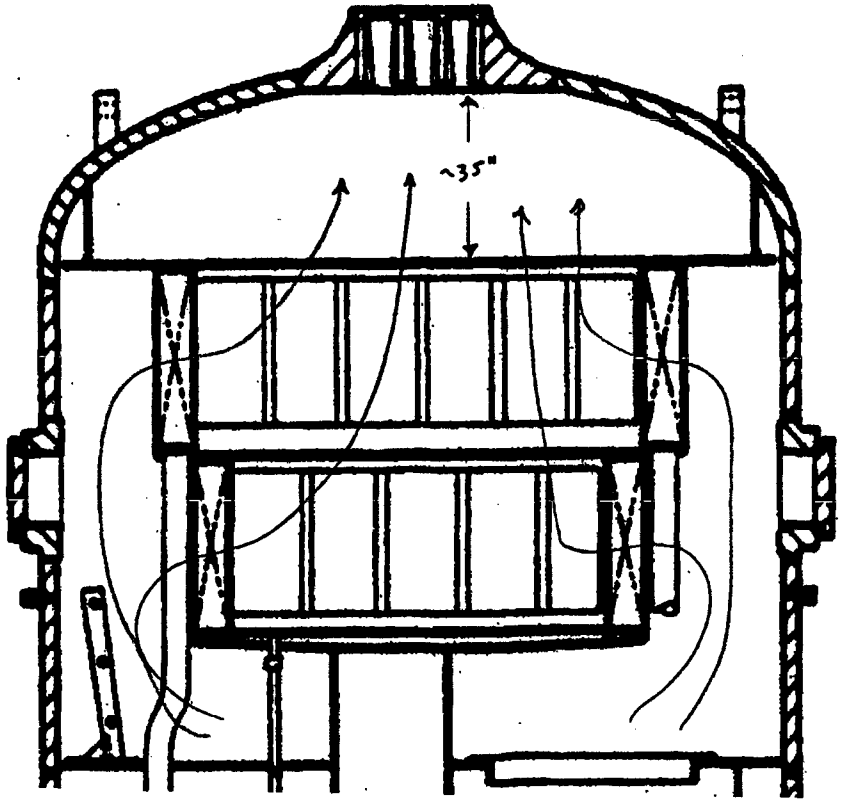
- Unit 1 – Model 54F
  - Steam Generator installed in 1R17
  - Designed for uprated conditions
    - Analysis performed using uprate operating conditions
- Unit 2 – Series 51M
  - Review for Flow Induced Vibration (FIV) affects showed acceptable results
  - Unsupported U-bends reviewed for increased fatigue
  - Increase in tube wear at Anti-Vibration Bar (AVB) interface evaluated

Steam Dryer Region BV

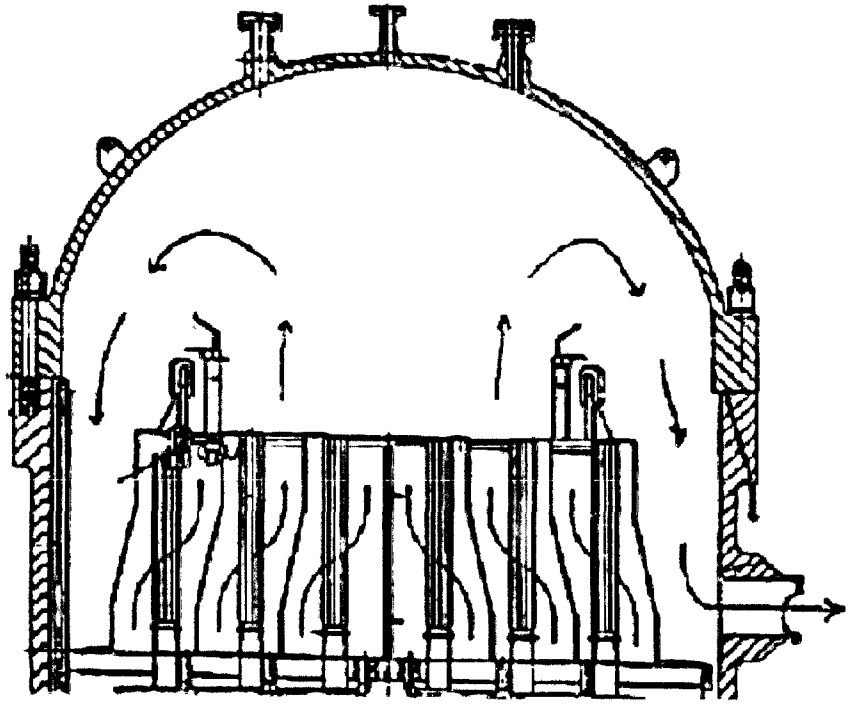
- Series 51/51M
  - Two Tier Arrangement
  - Series 51 M Includes ½" Thick Perforated Plate
  - Peerless Separator Vanes – Carbon Steel
  - Mounted From Top of SG on Support Ring
  - Supports Mid Deck Plate – Robust Structure
- Series 54F
  - Single Tier Arrangement
  - Includes Perforated Plate
  - Peerless Separator Vanes – Carbon Steel
  - Mounted From Top of SG on Support Ring

Steam Dryer Region

Series 51M



Typical BWR



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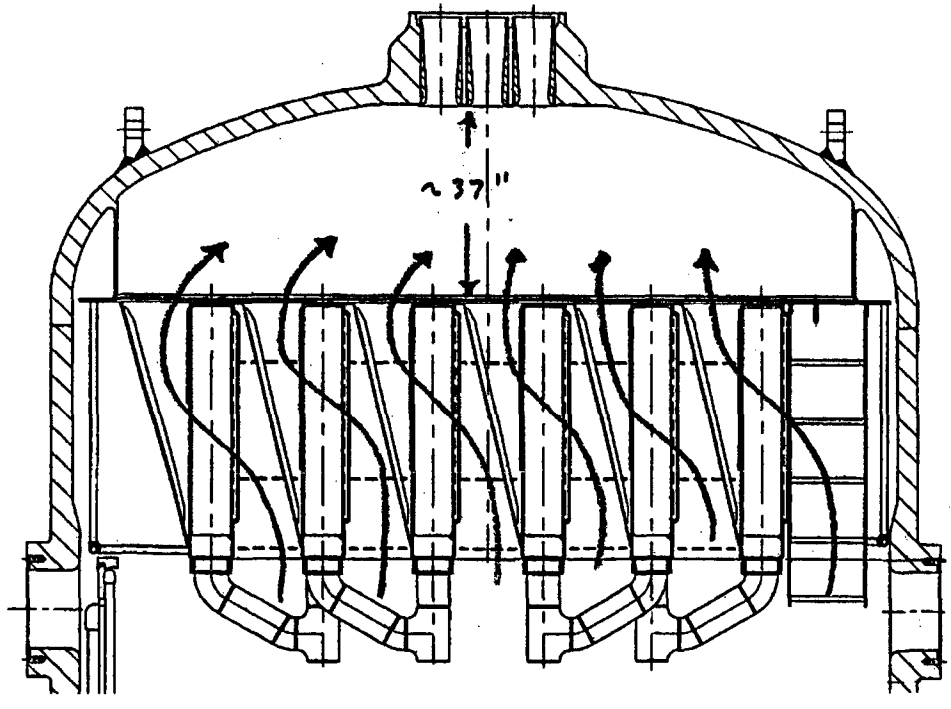
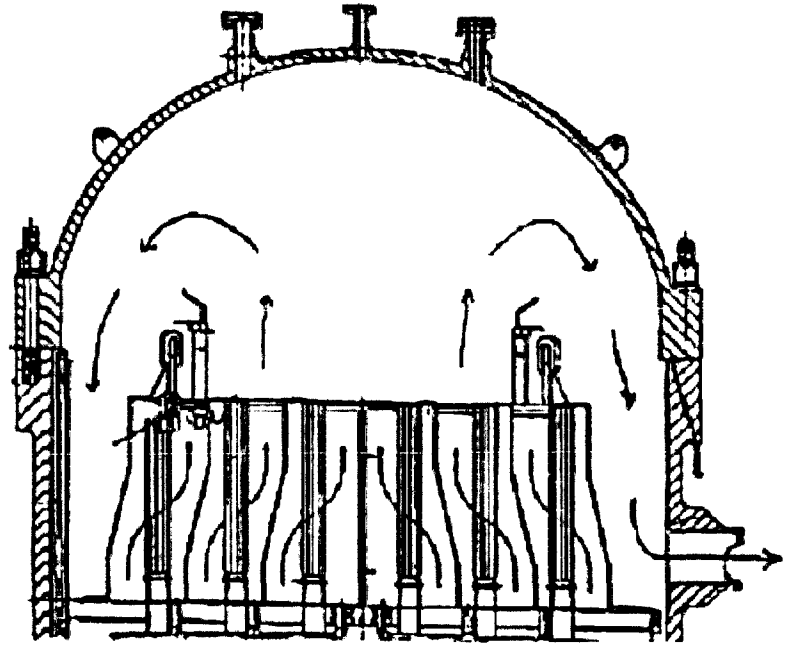
Steam Dryer Region

Series 54F



Typical BWR



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Steam Dryer FIV Comparison

- Series 51/51M
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.5 ft/sec
    - Post Uprate – 4.1 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 22 Domestic Plants
    - 74 Domestic SG
    - Operational from early 70's

- Series 54F
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.0 ft/sec
    - Post Uprate – 3.5 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 6 Domestic Plants
    - 18 Domestic SG
    - Operational from mid 90's

BOP Heat Exchanger Vibration

- Feedwater Heaters
- Moisture Separator Reheaters
  - Specific analysis confirmed acceptability of increased steam flow
- Condenser Tubing
  - BVPS-1 condenser tubes previously staked
  - BVPS-2 will be staked prior to power uprate

Vibration Monitoring

- Monitor Secondary systems pre and post EPU
  - Baseline walk downs conducted on each plant
  - Areas of interest targeted for inspection under EPU
- Utilize guidance from ASME OM-S/G-2003, Part 3
- Collect and review data at each of the power escalation plateau
- Inspections will be augmented as required with vibration monitoring equipment
- Large equipment (e.g. Reactor Coolant Pump, Turbine) monitored with existing plant instrumentation
  - Secondary pumps will also be monitored

Cooling Systems

- Systems remain capable of dissipating heat loads for normal, shutdown and accident conditions
- Flows are adequate without modification
  - River / Service water systems
  - Component cooling systems
  - Residual heat removal system
  - Safety Injection and Containment Depressurization systems

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Spent Fuel Cooling

- Spent fuel cooling previously evaluated for EPU conditions in Amendments 247 and 126 (100 hour minimum offload time)

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Auxiliary Feedwater

- Condensate Storage Tank sizing is based on amount of water required for 9 hours at hot standby conditions
  - New Tech Spec limits for EPU require a minimum useable volume of 130,000 gallons
- 2 auxiliary feedwater pumps required for certain accidents (FLB and LONF)
  - Tech Spec bases for BVPS-1 revised to be consistent with BVPS-2
  - Required due to incorporation of cavitating venturis at BVPS-1

Flow Accelerated Corrosion (FAC)

Dave Grabski

(FAC Program Owner)

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Flow Accelerated Corrosion

- EPU effects evaluated using CHECWORKS
- Turbine extraction steam tee proactively replaced
- Post Uprate Outage inspection sampling increased based on EPU conditions
- Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

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Risk Impact

Colin Keller
Supervisor, PRA

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Probabilistic Risk Assessment

- Risk Assessment
  - PRA Model Elements
  - Resultant CDF changes for each model

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Probabilistic Risk Assessment

- Initiating Events
  - No new initiators
  - No significant increase in Initiating Event frequencies due to the Power Uprate
- Success Criteria
  - MAAP analyses establishes EPU success criteria
    - Setpoint Changes due to Containment Conversion
    - New Pump Curves
  - No new accident sequences identified

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Risk Assessment

- Component and System Reliability
  - Comprehensive reviews of equipment performed
  - Systems operate within allowable limits
  - No impact on PRA failure rates or results
  - Existing monitoring programs will account for any additional system wear (Maintenance Rule, MSPI)
  - Future model updates will capture any initiating event or equipment failure rate changes

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Probabilistic Risk Assessment

- Operator Response Times / HRA
  - MAAP analyses to determine operator action time available
  - Higher decay heat reduced times for some operator actions
  - Most important impacts are:
    - Operator starts AFW given SSPS has failed and no SI signal present
    - Operator initiates bleed & feed
    - Reduction in time to recover from loss of shutdown cooling during reduced inventory

Probabilistic Risk Assessment

BVPS-1 Risk Important Operator Actions						
Operator Action	**Description**	**Pre-EPU Time**	**Pre- EPU HEP**	**Post-EPU Time**	**Post-EPU HEP**	**Confirmation Method**
OPROS6	Operator starts AFW given failure of SSPS for sequences in which there is no safety injection; e.g., turbine trip sequences.	62 minutes	8.15E-04	43 minutes	1.12E-03	Table-top & Simulator Observation
OPRWM1	Operator supplies borated makeup water to the RWST initially from the spent fuel pool, and, in the long term, from blending operations during an SGTR event	>24 hours	7.68E-03	>24 hours	7.68E-03	Table-top & Simulator Observation of Annunciators
OPRBV3	Operators set up and start portable diesel driven fans to cool the emergency switchgear rooms upon failure of the normal switchgear ventilation fans and the emergency switchgear ventilation fans.	30 minutes	7.11E-02	30 minutes	7.11E-02	Table-top & Simulator Observation of Annunciators
OPROC1	Operator trips RCP during loss of Primary Plant CCW.	5 minutes	4.79E-03	5 minutes	4.79E-03	Simulator Observation
OPROB2	Operators initiate bleed and feed operation by initiating safety injection, opening the PORVs, opening the PORV block valves, and verifying HHSI pump operation following failure to restore MFW and Dedicated AFW.	78 minutes	1.53E-02	29 minutes	1.68E-02	Table-top & Simulator Observation

Probabilistic Risk Assessment

BVPS-2 Risk Important Operator Actions						
Operator Action	**Description**	**Pre-EPU Time**	**Pre- EPU HEP**	**Post-EPU Time**	**Post-EPU HEP**	**Confirmation Method**
OPROB1	Operators initiate bleed-and-feed operation by initiating safety injection, opening the PORVs, reopening the PORV block valves, and verifying HHSI pump operation.	78 minutes	1.87E-03	64 minutes	2.15E-03	Table-top
OPRWM1	Operator supplies borated makeup water to the RWST initially from the spent fuel pool, and in the long term, with makeup from service water during an SGTR event.	>24 hours	5.97E-03	>24 hours	5.97E-03	Talk/Walk-thru of similar action for 2" LOCA
OPROF2	Operator opens main feed bypass valves following a partial feedwater isolation event after a plant trip.	78 minutes	2.93E-04	26 minutes	4.96E-04	Table-top
OPROS6	Operator starts AFW given failure of SSPS for sequences in which there is no safety injection; for example, turbine trip sequences.	78 minutes	1.00E-03	43 minutes	1.00E-03	Table-top
OPROT1	Operator pushes the manual reactor trip buttons after the Solid State Protection System (SSPS) fails to automatically actuate reactor trip in response to a plant trip condition.	1 minute	1.37E-03	1 minute	1.37E-03	Table-top

Probabilistic Risk Assessment

- Operator Response Times / HRA
  - Validation of operator time to complete actions was performed
  - Operator actions with small amount of time available can be performed within the time available

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Probabilistic Risk Assessment

- Shutdown Risk
  - EPU has no unique or significant impacts
  - No changes to shutdown operations or safe shutdown risk assessment

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Summary (Unit-1)

BVPS-1 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	2.25 E-05	2.29E-05	3.36E-07 *
Internal CDF (/year)	6.25 E-06	6.55 E-06	2.97 E-07
External CDF (/year)	1.63 E-05	1.63 E-05	3.95 E-08
Fire CDF (/year)	4.62 E-06	4.66 E-06	3.89 E-08
Total LERF (/year)	4.37 E-07	4.95 E-07	5.83 E-08 *

*Meets the threshold for risk significance as defined by Reg. Guide 1.174.

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Summary (Unit-2)

BVPS-2 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	3.30 E-05	3.33 E-05	3.55 E-07 *
Internal CDF (/year)	1.86 E-05	1.89 E-05	2.92 E-07
External CDF (/year)	1.44 E-05	1.45 E-05	6.32 E-08
Fire CDF (/year)	4.89 E-06	4.95 E-06	6.38 E-08
Total LERF (/year)	1.03 E-06	1.07 E-06	4.61 E-08 *

*Meets the threshold for risk significance as defined by Reg. Guide 1.174.

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PRA Conclusion

All PRA model elements reviewed for impact

- The increase in risk, due to the EPU for BVPS-1 and BVPS-2, meets the acceptance criteria as defined by Regulatory Guide 1.174
- Small change in operator time available
- Additional equipment has small impact on risk

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Operations and Testing

Don Durkosh
(Senior Reactor Operator)

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Operations and Testing – Agenda

- Human Factors
- Training
- Test Plan
- Large Transient Testing

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Human Factors -- Overview

- Minimal changes to control room (CR)
  - Six accumulator pressure indicators
  - Two containment pressure indicators
- EOPs upgraded to ERGs in 2003
- EPU procedure changes reflect revised operating parameters, limits & setpoints
- Added EOP Attachment for CR purge post-SGTR (existing SLB purge attachment)

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Human Factors -- Action Times

- Increased decay heat reduces available time to perform some operator actions:
  - The basic operator actions remain unchanged
  - No new modifications required
  - Most action times have remained unchanged or have increased
  - Procedure enhancements are being incorporated
  - Action times being re-validated (simulator, walk downs, Table-top, etc.)

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Reduced Operator Action Times

- ECCS Switchover (hot leg recirculation)
  - BVPS-1, 8 hours to 6.5 hours
  - BVPS-2, 7 hours to 6 hours
  - BVPS-2, 11.5 hours to 9.5 hours
- SGTR – Isolating AFW flow
- Post trip, fire – Restoring AFW flow

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SGTR Action Time

- Key Action:
  - Isolate AFW flow to ruptured S/G
- EPU analyses based on crew simulator data from 2002
- EPU validation status:
  - BVPS-1 simulator complete
  - BVPS-2 initial (Table-top) complete
  - BVPS-2 simulator (planned for later this year)

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Fire Scenario Action Time

- Key Action:
  - Re-establish AFW flow if lost during a fire incident
- BVPS-1 status:
  - Established operator action times
  - Enhanced the fire-related procedures
  - Completed walk downs to validate action times
- BVPS-2 status:
  - Procedures previously enhanced
  - Walk downs will be performed to validate action times

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Operator Training

- Classroom (Design Change packages)
  - Technical Specification & LRM changes
  - Plant (physical) changes
  - Procedure & setpoint changes
- Simulator Focus Areas
  - Demonstrations & hands on training
  - Transient response & EOP execution
- Power Ascension (Just-In-Time)
  - Startup/shutdown

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Operator Training (cont.)

- Crew training implemented prior to implementation of EPU-related plant modifications
- Plant-specific simulators are used
- Simulator changes are primarily software & initial condition differences that can easily be configured for current or EPU plant conditions

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Test Plan

- Post modification tests
- Low power physics tests
- Collect baseline data
- Power ascension in small increments
  - Perform data projections
  - Collect data at new steady state conditions
  - Review plant data & evaluate anomalies

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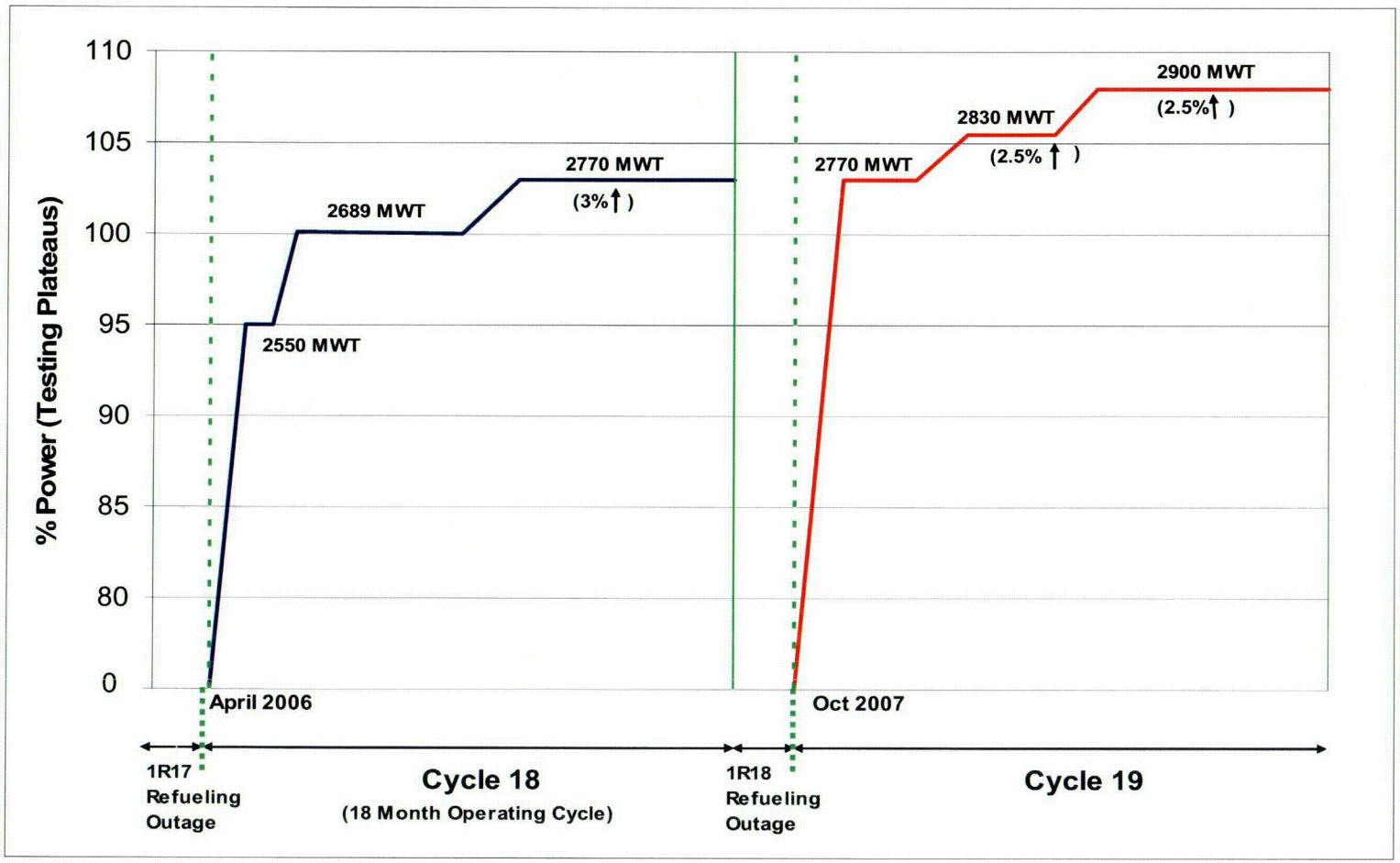
BVPS-1 Power Ascension Profiles

(NOTE - Timelines Not Drawn To Scale)



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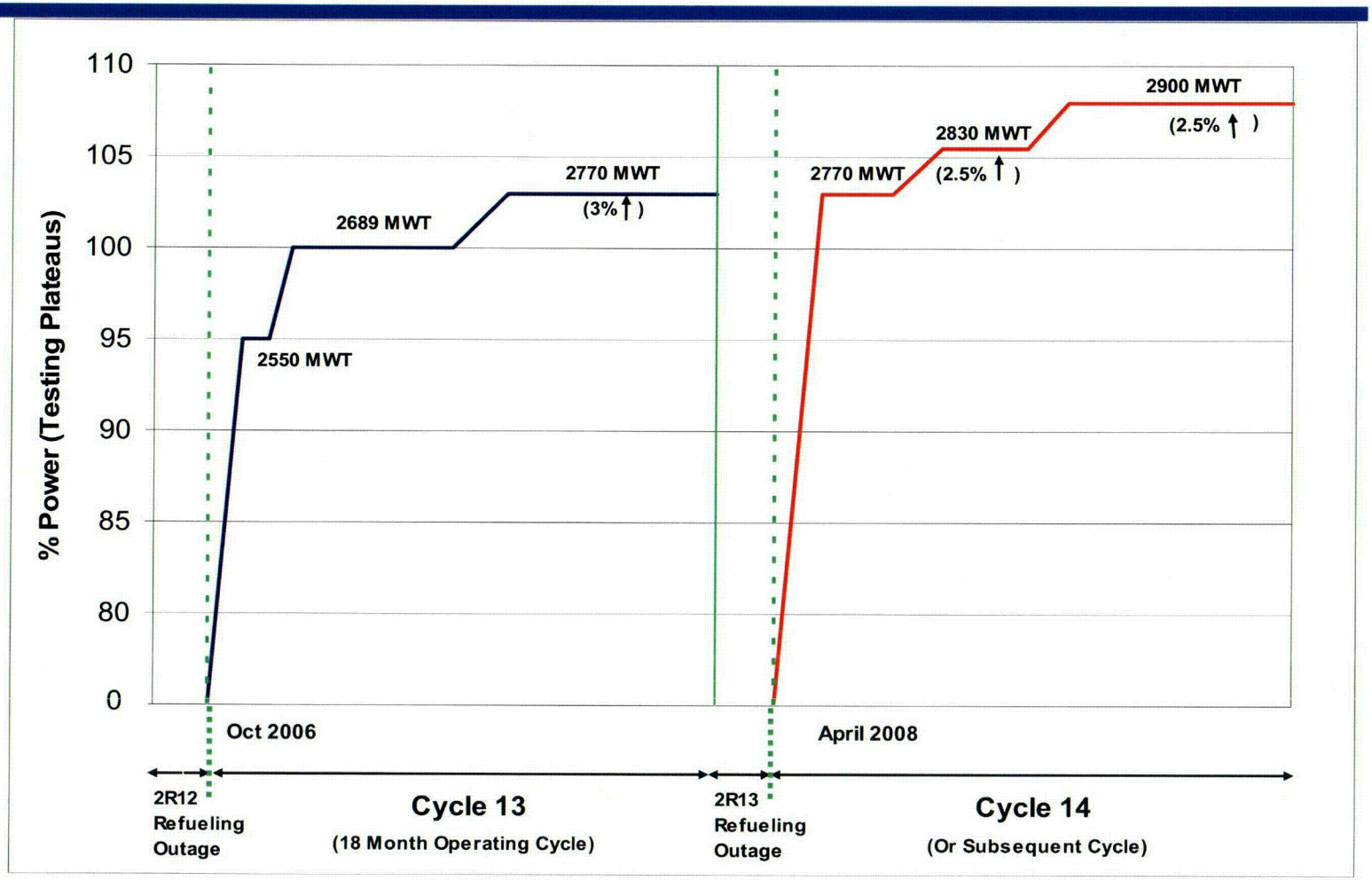
C06

BVPS-2 Power Ascension Profile

(NOTE - Timelines Not Drawn To Scale)



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C07

Transient Testing Considerations

- Evaluated modifications & control changes:
  - Modifications will be fully tested
  - Extensive Owner's review of NSSS Control supporting analyses:
    - No controller functional/logic changes
    - No new control schemes
    - Changes limited to setpoints (optimization)
- Aggregate impact does not adversely affect plant dynamic response

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Planned Testing, BVPS-1

- Monitor control system during start-up
- Perform a S/G level control test
  - Input step-change in "actual" level
  - Monitor controller response
  - Confirm integrated system response

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Large Transient Testing

- Turbine trip > 49% power results in reactor trip
- No functional change in NSSS controls and supporting reactor trip functions
- The NSSS simulation code/model:
  - Supported original plant NSSS control system design
  - Supports current plant NSSS operational analyses
  - Used to benchmark the BVPS simulators
  - Used in current & EPU non-LOCA safety analyses.
  - Used to optimize NSSS controls for EPU conditions
- As such, LTT is not necessary

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Operations & Testing -- Conclusions

- Procedure changes involve primarily operating parameters, limits & setpoints
- Power ascension process will ensure a controlled, closely monitored, conservative approach to the new licensed power level
- Plant modifications & NSSS control changes do not alter the basic design function nor introduce first-of-a-kind type changes that warrant LTT.

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Concluding Remarks

Site VP – Jim Lash

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Concluding Remarks

- Detailed and comprehensive reviews have been performed
- No safety issues identified
- Conservative phased approach to power escalation is being employed
- Beaver Valley Power Station safety and reliability will be maintained through plant modifications, procedure changes and training, and adherence to TS / Operating License

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End of Presentation

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